KJR

McNEES, WALLACE & NURICK

ATTORNEYS AT LAW

100 PINE STREET
P. O. BOX 1166
HARRISBURG, PA 17108-1166
TELEPHONE (717) 232-8000
FAX (717) 237-5300

BRUCE D. BAGLEY
TERRY R. BOSSERT
ALAN R. BOYNTON, JR.
ERIC L. BROSSMAN
ROBERT M. CHERRY
WILLIAM A. CHESNUTT
DAVID B. DISNEY
MICHAEL A. DOCTROW
ELIZABETH A. DOUGHERTY
HARVEY FREEDENBERG
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GARY A. RITTER
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ROBERT D. STETS
RICHARD W. STEVENSON
DIANE M. TOKARSKY

OF COUNSEL
ROBERT H. GRISWOLD
SAMUEL A. SCHRECKENGAUST, JR.

DAVID M. WATTS, JR.
STEVEN J. WEINGARTEN
NEAL S. WEST
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CATHERINE E. WALTERS
DERRICK P. WILLIAMSON

April 12, 1995

John G. Alford, Secretary
PA Public Utility Commission
B-20 North Office Building
P. O. Box 3265
Harrisburg, PA 17120

DOCUMENT FOLDER

VIA HAND DELIVERY

Re: Pennsylvania Public Utility Commission, et al. v. Pennsylvania Power & Light Company, Docket No. R-00943271

Dear Secretary Alford:

Enclosed for filing in the above-captioned proceeding, please find an original and two (2) copies of the following Direct Testimonies:

Stephen J. Baron on behalf of PP&L Industrial Customer Alliance;
Paul R. Williams on behalf of Air Products and Chemicals, Inc.;
James H. Rooney on behalf of Armstrong World Industries, Inc.;
Peter F. Chamberlain on behalf of BOC Gases;
Don A. Hornung on behalf of Hershey Foods Corporation, Inc.;
James S. Schneider on behalf of R. R. Donnelley & Sons, Inc.; and
Robert K. Felter on behalf of Thomson Consumer Electronics.

As evidenced by the attached Certificate of Service, all parties of record have been duly served.

Please date stamp a copy of this transmittal letter and kindly return for our filing purposes.

Very truly yours,

McNEES WALLACE & NURICK

By David M. Klepp

David M. Kleppinger

DMK/dt
Enclosures
cc: Certificate of Service

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

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APR 13 1995

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DIRECT TESTIMONY AND EXHIBITS OF STEPHEN J. BARON

ON BEHALF OF THE

PP&L INDUSTRIAL CUSTOMER ALLIANCE

Air Products and Chemicals, Inc.
Alumax Mill Products, Inc.
Appleton Papers Inc.
Armstrong World Industries, Inc.
BOC Gases
CertainTeed Corporation
Chamberlain Manufacturing Corporation
Cressona Aluminum Company
ESSROC Materials, Inc.
Grinnell Corporation
Hercules Cement Company
Hershey Foods Corporation
International Paper Company
Lafarge Whitehall Cement
Liquid Carbonic Industrial Gases
Magee Carpet Company
M&M/Mars, Inc.
Praxair, Inc.
R. R. Donnelley & Sons
The Stroh Brewery Company
Thomson Consumer Electronics, Inc.
Victaulic Company of America

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

APRIL 1995

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), Suite 475, 35 Glenlake Parkway, Atlanta, Georgia 30328.

Q. What is your occupation and by whom are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers.

The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than twenty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of Electrical World. My article on "Standby Electric Rates" was published in the November 8, 1984 issue of Public Utilities Fortnightly. In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, West Virginia, and the Federal Energy Regulatory Commission. A list of my specific regulatory appearances can be found in Exhibit ___ (SJB-1).

In the course of my professional career, I have analyzed and developed interruptible rates for numerous utility systems. I have presented testimony on the subject of interruptible electric rates on sixteen occasions before various regulatory commissions.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Pennsylvania Power & Light Industrial Customer Alliance ("PPLICA"), a group of large industrial customers of Pennsylvania Power & Light Company ("PP&L") who take firm and interruptible service primarily on Rate Schedule LP-5 and, under the Company's proposal in this case, will also take service on Rate Schedule LP-6.

Q. Would you please briefly describe the members of the PPLICA?

A. Yes. PPLICA consists of twenty-two large industrial customers engaged in manufacturing products such as food, consumer electronics, aluminum, paper, steel, building products, cement, and industrial gases. The members of PPLICA consume in excess of **2.4 billion** kWh's of electricity on the PP&L system on an annual basis and pay (at present rates) electric bills to PP&L of approximately $105 million. In general, these customers are engaged in manufacturing businesses that are domestic or global in nature with respect to both markets and competitors. The members of PPLICA employ more than 20,000 people in PP&L's service area, make more than $230 million per year in local purchases of goods and services, and pay more than

$64 million per year in state and local taxes. Finally, several PPLICA members have plants in other states, which compete with their Pennsylvania operations.

Q. What is the impact of PP&L's rate proposal in this case on the members of PPLICA?

A. As I indicated, at current rates, including the energy cost rate ("ECR") and other riders and surcharges, PPLICA industrial customers taking service on Rate Schedule LP-5 are paying annual revenues to PP&L of <u>$105 million</u>. PP&L is proposing annual revenue increases of <u>$19 million</u> to PPLICA member companies. This increase in electric charges to PPLICA members equates to an <u>18% annual increase</u>. This is substantially in excess of the Company's average requested increase of 11.7%.[1] I should also note that PPLICA, through the testimony of witnesses Kollen and Baudino, is challenging the Company's proposed revenue requirements and is recommending a substantial reduction to PP&L's requested increase.

A major reason for this substantial increase to PPLICA members is that more than half of the PPLICA usage is on the LP-5 interruptible rate. During the test year,

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[1] As I will discuss in the next section of my testimony, though PP&L has indicated throughout its filing that its requested increase is in the amount of $262 million (an 11.7% increase to rate schedule revenues), the actual amount requested by the Company is $240 million or a 10.6% increase to rate schedule revenues. This difference is due to the Company's assumption, which is not correct, that the ECR would be credited by the full amount of the test year level of PJM capacity credit, output reservation, and transmission entitlement revenues. These revenue credits of $22 million only occur at proposed rates.

42% of the kWh sales on Schedule LP-5 were made to interruptible customers. For PPLICA members taking service on the LP-5 interruptible rate, average increases of 25% will be experienced if PP&L's rate proposals are accepted by the Commission. Some PPLICA members will receive annual increases in excess of 36%.[2]

Q. Do you believe that PP&L's rate proposals reflect consideration of the emerging competitive environment facing the electric utility industry?

A. No. I do not believe that PP&L's LP-5 rate proposals have recognized this emerging competitive environment. For example, I have examined PP&L's current FERC full requirements tariff which the Company provided in response to an interrogatory of PPLICA (Set 3, Q.6.).

In this response, PP&L indicated that the currently effective FERC wholesale power rates represented "resale rates more in line with the market conditions for wholesale service." As a proxy for a market-based rate, this PP&L tariff represents a reasonable basis to assess the competitiveness of the Company's LP-5 rate proposals in this retail rate case.[3]

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[2] This 36% increase is calculated on the total bill, after accounting for the effects of the ECR roll-in, the roll-in of a portion of the Special Base Rate Adjustment charge, and the elimination of the STAS in proposed rates. The base rate increase to these customers exceeds 80%.

[3] Both the wholesale tariff and Schedule LP-5 serve customers taking service at 69,000 volts or higher.

Based on the Company's 1996 wholesale rates, including the fuel adjustment, PPLICA members would be charged $97 million annually. This represents a $8.7 million decrease from current rates, or 8.25%. Compared to PP&L's proposed rates in this rate case, the wholesale tariff would produce annual bills to PPLICA members that are 22% lower than proposed by PP&L ($28 million). It is also critically important to note that the wholesale rate calculation is based on a firm rate; the calculation of PPLICA charges at present LP-5 rates includes a substantial amount of interruptible load (an inferior quality service). It is obvious that, in a competitive environment, this could never occur. Clearly, the wholesale tariff, at the very least, could be used as a proxy for market-based rates. On this basis, PP&L's LP-5 rate increase proposal is not competitive.

Another example of this lack of competitiveness of the Company's proposed LP-5 rate is PP&L's own internal estimate of benchmark market prices for the years 1995 to 2000. According to PP&L witness Sipics, PP&L estimates that market prices will range from 2.7 cents per kWh in 1995 to 4.0 cents per kWh in the year 2000. PP&L's proposed firm LP-5 and LP-6 schedules have an average price of 6.25 cents per kWh and 5.8 cents per kWh, respectively, in 1995. Based on this comparison, PP&L's proposed LP-5 and LP-6 rates exceed market prices by about 120% in 1995.

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

A. I will be presenting testimony on a number of cost-of-service, revenue increase allocation, and rate design issues which affect the members of PPLICA, as well as other customers of PP&L. In addition, I will address two energy cost rate issues raised by the Company's filing in this proceeding. These issues relate to the proposal to include Jersey Central Power & Light Company ("JCP&L") off-system sales revenues within the ECR and the Company's proposal to include revenues from other off-system sales associated with PJM capacity credit sales, output reservation sales, and transmission entitlement sales within the ECR.

With respect to the cost-of-service, revenue increase allocation, and rate design issues, I will be presenting testimony regarding the appropriate cost-of-service study to utilize in this proceeding to establish class revenue requirements and ultimately a recommendation regarding the increases for each customer class. PP&L has proposed to utilize a 12 coincident peak ("CP") methodology in this proceeding. I will present testimony on the reasonableness of the Company's choice of a 12 CP methodology, as well as recommended modifications to the Company's 12 CP analysis which should be incorporated into any cost-of-service study adopted by the Commission in this proceeding.

With respect to the allocation of any rate increase granted to PP&L in this proceeding, I will propose a methodology which more reasonably moves class rates toward cost-of-service. As explained by PP&L witnesses in this proceeding, the

Company has attempted to move rates toward cost-of-service. However, as I will demonstrate, the Company's approach has not been systematic (with respect to all customer classes) and should be adjusted to provide for a more equitable and reasoned movement toward cost-of-service. I will recommend a methodology that specifically moves all customer class rates toward cost-of-service by means of reducing subsidies at present rates by 50% at proposed rates. A subsidy is defined as the difference between the revenue requirements necessary for a customer class to produce a rate of return equal to the system average rate of return and the actual revenues the class is producing. In the case of a customer class paying in excess of cost-of-service, this subsidy is the amount that the customer class is paying to other classes which are not paying their share of PP&L's costs. The methodology that I will recommend is a means to reduce these subsidies paid by customer classes that are overearned and at the same time reduce the deficiencies contained in rates for classes that are underearned.

The final set of issues which I will address in my testimony concerns the specific rate design proposal made by PP&L with respect to Rate Schedules LP-5 and the newly proposed Rate Schedule LP-6. In addition, I will address the Company's proposals with respect to interruptible rates associated with Rate Schedules LP-5 and LP-6.

With respect to the energy cost rate issues, I will be addressing two issues in this case which do not immediately impact the Company's requested $262 million increase. These issues concern a proposal by the Company to modify its energy cost rate to effectively allow an automatic increase to retail customers to offset reduced future revenues associated with its sale of capacity to JCP&L. I will discuss the ramifications of this proposal and make a recommendation which I believe is an appropriate ratemaking treatment for this type of transaction.

In addition, I will address the Company's proposal to include, in the ECR, on a permanent basis, the amounts of revenue credits associated with PJM capacity credit, output reservation and transmission entitlement sales. At the current time, a portion of these sales is included as an offset to the ECR as a result of the settlement in Docket No. M-00930406. The Company is proposing to transfer 100% of these revenue credits into the ECR on a permanent basis and essentially transfer the risk associated with these sales to retail customers. The alternative of retaining these revenue credits in base rates transfers the risk of future sales decreases, or the benefits of increases, to the Company.

Q. You previously noted (footnote 1) that PP&L is actually requesting a $240 million increase in this case rather than its stated increase of $262 million. Would you please explain how this has occurred?

A. PP&L is proposing to include all of the revenues that it receives from off-system PJM capacity credit sales, output reservation sales and transmission entitlement sales ("capacity sales") in its ECR as a credit (reduction) to fuel cost, <u>if</u> it also receives approval from the Commission to automatically recover lost JCP&L capacity sale revenues within the ECR. If the Commission does not approve the Company's JCP&L recovery mechanism, PP&L proposes to simply credit these off-system capacity sales revenues to base rates at a fixed, test year level. As I will discuss subsequently in my testimony, I am recommending that PP&L's JCP&L proposal be rejected and that all test year levels of capacity sales revenues be credited to base rate revenue requirements, irrespective of the Commission's disposition of the JCP&L issues. These revenues amount to approximately $22 million in the test year (including gross receipts taxes).

Q. How has the Company treated these revenues in its filing?

A. PP&L has prepared its filing under the assumption that it will receive its requested JCP&L rate recovery. As a result, it developed its proposed rates to reflect the full amount of the $22 million in capacity credit sales revenues in the ECR. In other words, proposed <u>base</u> rates do not include any credit for the Company's test year off-system capacity sales (base rates are higher than they otherwise would be). However, customers do receive the appropriate benefit of these revenue credits through the

ECR. Thus, in total, proposed base rates plus the proposed ECR properly reflect the Company's claimed cost of service.

However, PP&L also included the $22 million capacity credit sales revenues as an offset to the <u>ECR at present rates</u>. In computing test year present rate revenues, PP&L assumed that it would pass along to customers, through the ECR, the full amount of the $22 million in capacity credit revenues. Effectively, the Company's filing implied that the test year ECR would be lower by the full amount of the capacity credit sales revenues, even if PP&L had not filed this rate case. This is an incorrect assumption since it is clear that PP&L would not pass these benefits to ratepayers, absent a rate case and absent its JCP&L lost revenue recovery proposal.

Q. What is the impact of PP&L assuming that present rates would be credited with the full amount of the off-system capacity credit sales revenues within the ECR?

A. The main impact is that PP&L understated present rate revenues by $22 million in its filing. By assuming that these off-system sales revenues would in fact be passed on to customers, regardless of this rate case, the Company understated test year revenues at present rates. As a result, the difference between present PP&L rates and its requested proposed rates is $240 million, not $262 million.

Q. How does this affect the Company's filed proposed rates?

A. Since the capacity credit revenues should properly be included at proposed rates, it does not impact the Company's proposed revenue requirement or its proposed rates, except that the ECR credit for these capacity sales should be rolled-in to proposed base rates rather than remain in the ECR. However, there is no difference in total rate schedule revenues at proposed rates (i.e., proposed base rates plus the proposed ECR properly reflects the Company's claimed revenue requirement).

Q. How did you treat this issue in your analysis and in the remainder of your testimony?

A. Since the Company's filing was premised on an assumption that the ECR at present rates would include the full off-system capacity sales credit revenues, I have chosen to prepare my analysis similarly. I believe that this will facilitate a reasonable comparison between the cost of service and rate design recommendations that I am making, and the Company's presentation.

Based on my analysis of the impact of the understated present rate revenues on cost of service study results, I believe that the analyses and recommendations which I will present in the remainder of my testimony, using the Company's filing assumptions, are not affected by this problem. In particular, the cost of service results (in terms of relative rate of return indices) are largely unaffected by this issue.

In summary, the cost-of-service, revenue increase distribution and rate design recommendations which I will make in my testimony are appropriate and should be adopted, regardless of whether or not the Company receives its requested treatment of lost JCP&L revenues or whether the present rate ECR during the test year includes an excess level of revenue credits.

Q. Would you please summarize your testimony?

A.

- **The appropriate basis for allocating production and transmission demand cost on the PP&L system is the single winter coincident peak methodology. However, given the Commission's adoption of the 12 CP methodology in previous PP&L rate cases, it is reasonable to accept PP&L's filed 12 CP study in this proceeding, if it is modified to reflect the following three specific adjustments:**

    1) Modify PP&L's treatment of interruptible load within the cost-of-service study.

    2) Reclassify non-utility generator expenses into both a demand related portion and an energy-related portion, following the treatment proposed by PP&L within the ECR.

    3) Allocate the costs associated with Economic Development Initiatives (and IDI) to all rate classes in recognition of the overall systemwide economic benefits of the program.

- **Any Commission-authorized rate increase should be allocated to customer classes on the basis of a "50% subsidy reduction" criterion, using the results of the PPLICA 12 CP cost-of-service study. In addition, to recognize the principle of gradualism in ratemaking, no rate schedule (including LP-5 interruptible) should receive an increase in excess of 1.5 times the system average rate schedule increase.**

- **PP&L's proposed LP-5 firm and LP-6 firm rate structures should be accepted, subject to the PPLICA-recommended increases for those rate schedules. PP&L's proposed interruptible rate for LP-5 and LP-6 should be rejected. The current PP&L LP-5 interruptible rate schedule should be continued for both LP-5 and proposed LP-6 customers, subject to the PPLICA recommended increase for that rate schedule.**

- **The appropriate basis to develop an interruptible rate is a cost-of-service approach, rather than the "resource value" method recommended by PP&L. PP&L's proposal is discriminatory since it inappropriately assumes that such customers are "selling" capacity to PP&L, rather than buying low-quality interruptible service from the Company.**

- **PP&L's proposal to automatically recover future revenue requirements associated with the phased termination of the 945 mW capacity sale to JCP&L within the ECR should be rejected. These increases amount to a single issue, <u>automatic</u>, rate case, with no consideration of other revenue requirements issues that would normally occur in a full base rate proceeding. Finally, PP&L's proposal effectively eliminates the incentive for the Company to sell this capacity in the competitive wholesale market or in a developing retail market.**

- **PP&L's proposal to include off-system capacity credit, output reservation, and transmission entitlement revenues as a credit within the ECR should be rejected. These revenue credits should be included in base rates at test year levels, like any other revenue or expense adjustment in the test year.**

III. COST-OF-SERVICE ISSUES

Q. Would you please briefly discuss the methodology PP&L is proposing in this proceeding to allocate retail jurisdictional costs to customer classes?

A. As in past PP&L rate cases, the Company is proposing to utilize a 12 CP allocation methodology in this proceeding. This approach assigns production and transmission demand costs on the basis of the average of the twelve monthly contributions of each customer class to the twelve month average system peak. This method, in contrast to a single coincident peak methodology, is premised on an assumption that load at the time of each month's peak is equally important in determining the amount and cost of generating capacity on the PP&L system. As noted in the testimony of PP&L witness Joseph M. Kleha, the Company utilized this methodology in its last base rate filing at Docket No. R-842651 and has continued to utilize this methodology in various Federal Energy Regulatory Commission ("FERC") proceedings. Mr. Kleha also noted that the Pennsylvania Commission determined ". . . that it was acceptable in PP&L's last base rate case." (Kleha testimony, page 6, line 11)

Q. What rationale does the Company rely on to support its adoption of a 12 CP cost-of-service methodology for retail cost allocation?

A. The Company has cited four supporting reasons for its selection of the 12 CP method. The first reason is simply the fact that it has used this methodology in the past. The second consideration mentioned by PP&L witness Kleha concerns his assertion that the use of a 12 CP methodology is consistent with the PJM capacity obligation for PP&L. However, based on Mr. Sipics' testimony, PP&L's primary obligation is to maintain a 12% reserve margin over the Company's winter peak, not the average of the Company's twelve peaks. There is no dispute with regard to the fact that PP&L must have sufficient capacity to meet its loads each month (as well as each hour), but the planning criterion driving costs on the PP&L system would appear to be its requirements to meet a winter peak.

The third consideration provided by the Company in support of its use of the 12 CP methodology is "recognition of seasonal class diversities." Although a 12 CP method does recognize the variability in each class' maximum monthly demands, this does not provide a rationale as to why the Company constructs generating capacity. Finally, the Company cites as a consideration in its selection of the 12 CP method the fact that scheduling generation equipment for maintenance occurs throughout the year. As a result, the Company presumably must consider the relationship between available capacity and customer demand each and every month. Although maintenance is clearly a consideration in the Company's planning, the driving force behind the addition of generating capacity to the PP&L system is the requirement to meet its winter peak demand.

Q. Based on your comments, do you believe that the 12 CP methodology should be utilized in this proceeding to allocate costs to retail customer classes?

A. No. I believe that a single coincident peak methodology, based on the winter peak of PP&L during the test year, should be the basis for allocating costs to the customer classes.

As I mentioned previously, and as PP&L witness Mr. Sipics discusses, the Company must maintain a 12% reserve margin over its winter peak demand to satisfy PJM capacity obligations. This is the driving force in capacity cost incurred and thus, on a cost causation basis, it is customer class contributions to the PP&L winter peak that should be used in a cost-of-service study.

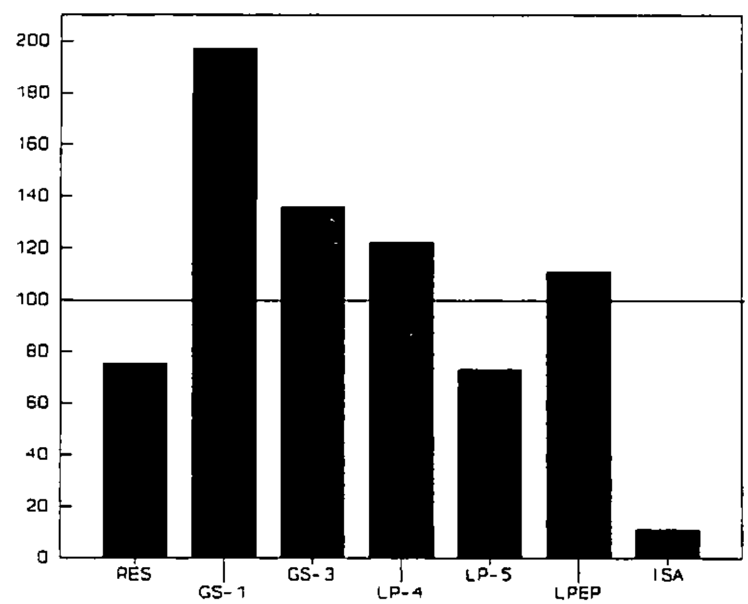
However, given the Company's prior use of the 12 CP method and the Commission's adoption of this method in the last PP&L case, I am not utilizing my preferred single CP methodology in this proceeding. The recommendations that I will make regarding cost-of-service and the revenue increase allocation to customer classes are premised on a 12 CP methodology. As I will discuss, however, there are a number of modifications to the Company's 12 CP cost study which must be made if the 12 CP study is relied upon to allocate cost in this proceeding.

Q. What were the results of the Company's 12 CP cost-of-service study at present rates?

A. As presented by PP&L witness Kleha, the Company's 12 CP study at present rates shows the residential class, Schedule LP-5, and Schedule ISA (Interruptible Service by Agreement) earning below the system average rate of return, with other classes earning above the system average rate of return. Figure 1 shows the relative rate of return indices based on the Company's filed 12 CP cost-of-service study at present rates. These indices represent the ratio of each class' rate of return on rate base to the system average rate of return.

FIGURE 1

PP&L'S 12 CP COST-OF-SERVICE STUDY
CLASS RELATIVE RATE OF RETURN INDICES
PRESENT RATES

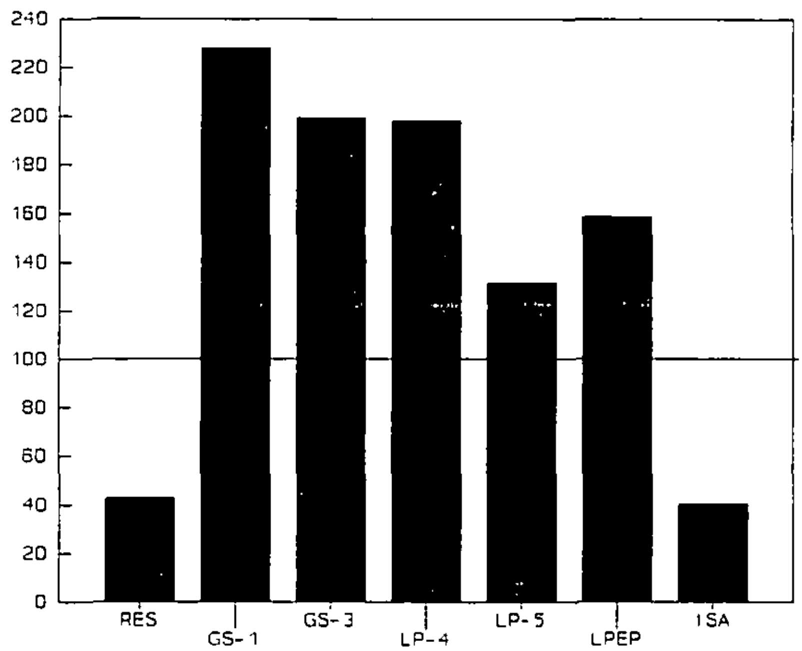


Q. Although you have indicated that you are not relying on the Company's single coincident peak (winter peak) cost-of-service study, what are the relative rate of return indices at present rates utilizing this methodology for cost allocation?

A. Figure 2 shows the relative rate of return indices at present rates using PP&L's filed single coincident peak cost-of-service study. As can be seen, under the single coincident peak methodology, both residential customers and Rate Schedule ISA continue to earn below the system rate of return, while all other classes produced returns in excess of the system average. It should be noted that in both of these graphs (Figures 1 and 2), the lighting class and some of the smaller rate schedules have been omitted for ease of presentation.

FIGURE 2

**PP&L'S 1 CP COST-OF-SERVICE STUDY
CLASS RELATIVE RATE OF RETURN INDICES
PRESENT RATES**



Q. You have indicated that you are relying on a 12 CP methodology for retail cost-of-service analysis in this proceeding. Does this mean that you agree with <u>the Company's filed 12 CP</u> cost-of-service study?

A. No. Based on my review of PP&L's filing, I have found three specific adjustments that should be made to the Company's cost-of-service study to more accurately reflect the rate of return produced by each customer class at present rates. These three adjustments relate to:

1) the Company's proposed treatment of interruptible load within the cost-of-service study,

2) the classification (between energy and demand) of payments to non-utility generators ("NUG"), and

3) the allocation of the costs associated with economic development and industrial development credits within the cost-of-service study.

I believe that the Company's cost study must be adjusted to reflect changes in the treatment of each of these three elements in order to properly reflect the cost associated with serving each customer class.

Q. **Would you please discuss the first adjustment which you believe is necessary to the Company's 12 CP cost-of-service study?**

A. The first adjustment concerns the methodology utilized by PP&L to reflect the presence of interruptible load on Rate Schedules LP-5, LP-4, and ISA. As discussed by PP&L witness Kleha, the Company recognized the presence of interruptible load on these three rate schedules by applying a $300 per kW credit to electric plant in-service for each kW of interruptible load on these three rate schedules. This is shown as a separate row in the Company's cost-of-service study, labeled "IL Capacity Value Effect." The total cost of the credit is approximately $86 million. This $86 million cost is then spread to all customer classes (including LP-5, LP-4, and ISA) as a cost-of-service). Rate Schedules LP-4, LP-5 and ISA receive a proportionate share of the "cost" associated with interruptible load.

Q. Do you agree with the Company's methodology to reflect the presence of interruptible load in each of the three rate classes identified?

A. No. I do not agree with the Company's proposal to base its interruptible rates on a "resource value" approach. Subsequently in my testimony, I will discuss the Company's specific proposal to institute a "resource value" based interruptible credit and will recommend using a cost-of-service approach to establish the interruptible tariffs in this proceeding. I strongly disagree with the Company's specific treatment of its interruptible customers within the cost-of-service study. However, even if one accepts the Company's basic framework, which argues that interruptible load is essentially equivalent to combustion turbine capacity, the company's recognition of this in its retail cost-of-service analysis is not correct.

Q. Would you please explain your concern with PP&L's treatment of interruptible load in the cost-of-service study?

A. The Company's cost-of-service analysis in this case for Rate Schedule LP-5 (as well as Rates LP-4 and ISA) utilizes the actual revenues produced by both firm and interruptible customers during the test year. For Rate Schedule LP-5, these revenues include a substantial amount from interruptible customers ($91.6 million), out of a total LP-5 revenue level during the test year at present rates of $259.6 million. These interruptible revenues are based on the Company's current interruptible rate schedule, which is optional to Rate LP-5. It reflects a current interruptible credit substantially in excess of the revenue requirement effect of PP&L's flawed $300 per kW credit methodology that is included as the value of interruptible load in the cost-of-service study.

Use of this approach contributes to Rate Schedule LP-5 earning a return below the system average rate of return during the test year. The Company's cost-of-service methodology in this case assumes that <u>all</u> LP-5 load is firm. The $300 per kW plant-in-service credit is used as a means to partially offset the reduction in revenues associated with the current optional interruptible rate for LP-5 customers. For example, if it is assumed that the current interruptible credit in Rate Schedule LP-5 (for each kW of interruptible load) is $12 per kW and the revenue requirements associated with PP&L's assumed $300 per kW plant-in-service credit is $3.00 per kW, the $9.00 per kW difference shows up as a <u>failure of LP-5 customers to produce sufficient revenues to cover its cost-of-service.</u>[4]

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[4] The revenue requirement associated with $300 of rate base is approximately $3.00 per kW per month.

Q. Isn't this necessary if one were to accept the Company's resource value approach in developing interruptible rates?

A. In part this is correct. Essentially, if the Company's resource value approach were accepted by the Commission and it was determined that the current interruptible rate is below the level that should be charged to these customers, the cost-of-service study, under the Company's methodology, would reflect the necessary revenue deficiency (in terms of rate of return) and indicate the need for a larger increase.

However, the Company's methodology in this proceeding assumes that the interruptible credit is a plant-in-service (rate base item) credit of $300 per kW, which translates into a revenue requirement of approximately $3.00 per kW month. The actual interruptible credit being proposed by the Company in this proceeding is $6.00 per kW for two hour interruptible load and a credit of $8.00 per kW for "thirty minute notice" interruptible load. These credits are close to a credit based on the PJM capacity deficiency rate, when it is adjusted for the active load management ("ALM") factor ($7.24 per kW). This methodology continues to reflect the Company's resource value approach, in contrast to the cost-of-service methodology that I will recommend.

Q. What is the implication of this mismatch in the Company's analysis?

A. The end result of PP&L's approach is to penalize customer classes that contain interruptible load by requiring these classes to pay the difference (assuming that rates were set at cost-of-service) between the "$300 resource value" assumed by the Company in its cost-of-service study and the actual credits being proposed for these customers of $6.00 and $8.00 per kW month. Essentially, the Company is charging back, through the cost-of-service study, the difference between the $3.00 credit contained in the cost study and the proposed credits of $6.00 and $8.00 directly to the affected classes. This is an inappropriate treatment for cost-of-service purposes and does not reflect a reasonable methodology for measuring each customer class' contribution to the overall system revenue requirements.

Q. What is your recommendation with respect to a proper treatment of interruptible load in the Company's cost-of-service study?

A. Although, as I will discuss subsequently in my testimony, I believe that a cost-of-service approach rather than a "resource value" approach to interruptible rate design is more appropriate and reasonable, even if one were to adopt the Company's resource value methodology, a proper treatment of interruptible load in this cost-of-service study would require that <u>the proposed interruptible credits of $6.00 and $8.00 per kW be utilized as the basis for measuring the value of interruptible load for cost-of-service analysis purposes</u>.

The adjustment to the Company's study that I recommend is to include a revenue credit for each customer class containing interruptible load (i.e., Rate Schedules LP-4, LP-5 and ISA) equivalent to the revenue credits actually being proposed by the Company for interruptible load. This is the PP&L proposed measure of the value of interruptible load, as embodied in its rate proposals. This methodology would work in a similar fashion to that proposed by the Company, except that a revenue credit would be applied to each of the three interruptible rate classes equivalent to the actual dollar amount of interruptible credits being proposed in this case, instead of the plant-in-service credit proposed by the Company. The cost of paying these revenue credits would then be allocated to all customer classes, including Rate Schedules LP-4, LP-5 and ISA, on the basis of the 12 CP production demand allocation factor. I believe that this adjustment is more reasonable and provides a more realistic measure of the cost of serving each rate class on the PP&L system. Again, the adjustment that I am recommending continues to adopt, for cost allocation purposes only, the Company's basic resource value approach. The difference between my methodology and that proposed by the Company is the recognition that the actual interruptible credits being proposed by PP&L in this case are in excess of the implied credit utilized in the cost-of-service study. The methodology that I am recommending corrects the mismatch contained in the Company's analysis.

Q. Would you please discuss your next proposed adjustment to the Company's cost-of-service study?

A. The next adjustment that I have made to the Company's 12 CP cost-of-service study concerns the classification and allocation of NUG purchased power expenses, reflecting the cost of payments made to NUGs by PP&L during the test year. PP&L has included $219,813,000 of NUG purchased power expenses in its retail cost-of-service analysis. The Company has allocated this purchased power expense on a 100% energy basis to customer classes. PP&L has argued that since it pays NUGs on a per kWh basis (reflecting an energy-only avoided cost), this is a reasonable assignment.

Q. Do you agree with the Company's classification and allocation of NUG purchased power expenses?

A. No. PP&L has failed to provide a consistent allocation of these expenses relative to the treatment of the revenues associated with the recovery of these cost from customers within the ECR. PP&L recovers the entire amount of NUG expenses (payments to NUGs) within the ECR from its retail customers. In Docket No. M-00930406, a settlement was approved by the Commission wherein a portion of these NUG expenses was classified as demand-related and allocated to customer classes on a demand basis within the ECR. PP&L continues to recover the entire amount of NUG expenses within the ECR, except that a portion is assigned on a demand basis and a portion on an energy basis.

PP&L Exhibit Future 1, Schedule D-3, provides the computational support for the Company's ECR revenues in this proceeding. On pages 8 through 11 of Schedule D-3, PP&L witness Kleha provides an analysis which computes the demand portion of the NUG revenue requirement responsibility for each class. This methodology follows the approach agreed to in the settlement of Docket No. M-00930406. As a result of the Company's adherence (in this rate case) to the Settlement Agreement with respect to the classification of a certain portion of NUG payments as demand related, there is a mismatch between the revenues attributed to each customer class associated with NUG expenses and the assignment of the corresponding cost contained in the cost-of-service study. This mismatch biases the Company's 12 CP cost-of-service results.[5]

Q. **What corrections should be made to the allocation of NUG purchased power expenses within the 12 CP cost-of-service study to correct this mismatch which you have identified?**

A. A proper cost-of-service analysis would classify the same portion of NUG expenses as demand related as is assumed by the Company in the ECR revenue analysis contained in Schedule D-3. On a total Company basis, payments to NUGs are $229,157,300. Of this amount, $191,629,460 is energy related and $37,527,840 is

[5] This error also is present in the Company's other cost-of-service studies (e.g., the Winter Peak study).

demand-related. This is shown on pages 10 and 11 of Schedule D-3 of Exhibit Future 1. Based on the Company's analysis, 16.38% of total NUG purchased power expenses are demand-related. To correct the Company's cost-of-service study, the retail portion of NUG purchased power expenses of $219,813,000 should be classified as 16.38% demand-related and 83.62% energy-related. With this adjustment, the allocation of NUG expenses will be consistent with its treatment of NUG expenses within the ECR.

Q. Why is it necessary to properly match the ECR revenue treatment of NUG payments with the cost-of-service allocation of the NUG expenses?

A. As I indicated, the Company has treated NUG expenses as both demand- and energy-related within the ECR and assigned cost recovery to customer classes (again within the ECR) on this basis. As a result, high load factor classes receive a somewhat lower assignment of the demand-related portion of the NUG payments than they would had those demand-related costs been assigned on a kWh basis. Everything else being equal, the revenues produced within the ECR for, say, Rate Schedule LP-5, are lower as a result of this treatment of NUG payments within the ECR. This is a Commission-approved and reasonable approach to the recovery of PP&L's NUG expenses and should be continued.

However, at the same time, PP&L has implicitly ignored this demand/energy classification of NUG payments in the cost-of-service analysis by allocating 100% of the retail NUG payment costs to rate classes <u>on an energy basis</u>. This assigns a more than proportionate share of NUG expenses to high load factor customer classes such as Rate Schedule LP-5.

As a result, the cost-of-service study now assigns <u>revenues</u> associated with NUG payments on a less than proportionate basis than the <u>costs</u> of the NUG payments, to Rate Schedule LP-5 and other higher load factor classes. The end result of this process is to portray a lower rate of return on rate base than is actually produced by Rate Schedule LP-5, due to the mismatch. Everything else being equal, the lower rate of return produced by this biased treatment of NUG expenses <u>implies a larger base rate increase for Rate Schedule LP-5</u> due to the cost-of-service results.[6] I believe that it is essential to correct this mismatch in the 12 CP cost-of-service study in order to produce a reasonable estimate of each class' cost-of-service. These cost study results can then be used to assign the increase approved by the Commission in this proceeding.

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6 For example, if LP-5 customers paid $800 of NUG expenses through the ECR (due to the demand/energy classification) and were allocated $1000 of the NUG expenses in the cost study, the effect on LP-5 operating income (before taxes) would be a <u>deficit</u> of $200, thus depressing the LP-5 rate of return. LP-5 customers would appear to be underpaying by $200 when, in fact, they are really paying their full share of NUG expenses.

Q. Would you please discuss the final adjustment you have made to the Company's 12 CP cost-of-service study?

A. The third and final adjustment that I have made to PP&L's cost study concerns the treatment of revenue credits associated with the Economic Development Initiatives Rider ("EDI") and Industrial Development Initiatives Rider ("IDI"). During the projected test year, the Company anticipates EDI and IDI credits to retail commercial and industrial customers of $30.624 million, at present rates. These economic development credits to customer bills were approved by the Pennsylvania Commission in a number of proceedings, including the most recent changes submitted by the Company in June 1992. In that filing (IV) of the Company's EDI, PP&L indicated that it is updating and revising its economic development tariffs in response to "increasingly competitive economic conditions." The Company's filing, goes on to state as follows:

> **"Specifically, PP&L, through discussions with its Large Customer Advisory Panel and various surveys with its large customers, has been made aware that regional, national and global economic developments are placing increased competitive demands on businesses located in PP&L's service territory, and that PP&L's large industrial customers want PP&L to assist them in improving and maintaining their competitiveness. PP&L is responding to the competitive economic concerns of is customers through this filing."** (PP&L Economic Development Initiatives - Phase IV, June 1, 1992, page 3)

PP&L continues to offer these EDI credits and IDI credits to its customers in this rate proceeding, although it intends to phase these credits out in future years.

Q. How did the Company treat the EDI and IDI credits in its 12 CP cost-of-service study?

A. The Company did not specifically identify as a separate element of cost-of-service the credits paid to existing and new commercial and industrial customers through its EDI and IDI programs. Rather, PP&L simply included credits paid to customers as an offset to revenues in the rate schedules in which these customers reside, principally Rate Schedules LP-4, LP-5 and ISA. The effect of this was to reduce revenues for these rate schedules within the cost study. Furthermore, the <u>costs</u> associated with these economic industrial development credits were implicitly assigned <u>directly to the rate schedules in which the customers receiving these credits reside</u>.

Q. Do you agree with the Company's treatment of these EDI and IDI revenue credits within the cost-of-service study?

A. No. Without specifically stating its methodology, the Company has effectively assigned the costs associated with these economic and industrial development credits to the rate schedules in which customers receiving those credits happen to take service. This is an inappropriate ratemaking treatment for credits, which, I believe the Company would agree, benefit all customers on the system and not simply customers who take service on the same rate schedules as the customers receiving the credits.

For example, in its June 1, 1992 filing at page 4 the Company stated as follows:

> **"Because the new Industrial Development Initiatives Rider is available only for incremental load, and only for a stated period of time, PP&L believes this proposal will have an indirect positive rate impact upon non-participating customers. In addition, to the extent that the proposals in this filing attract new industry to central-eastern Pennsylvania, all of PP&L's ratepayers should benefit from an improved economic climate. . . . In the future, PP&L's ratepayers could be subject to increased cost recovery if these existing businesses were to close down or leave the service territory."** (PP&L Economic Development Initiatives - Phase IV, June 1, 1992, page 4)

Again on page 10 of the Company's filing, PP&L stated:

> **"Specifically, to the extent that existing EDI Rider customers remain in the service territory or expand their operations, other customers will benefit from stabilized or reduced costs in any future rate filings, all other things being equal."** (Ibid., page 10)

Q. Do you believe that it was the intent of the PP&L Economic Development Initiative to retain existing customers and attract new load for the benefit of all ratepayers on the PP&L system?

A. Yes. Based on the Company's filing seeking approval of these riders, the intent of the EDI program was to benefit all PP&L customers, as well as the customers receiving the revenue credits. As such, a reasonable cost-of-service treatment of these credits would assign the cost to all rate classes, rather than simply assigning the costs of the credits to the rate classes in which customers receiving the credits happen to reside.

The flaw in the Company's methodology can be seen by examining the impact on Rate Schedule ISA. There is only one customer on Rate Schedule ISA, and that one customer is receiving approximately $872,000 of credits at present rates. Under the Company's cost-of-service methodology, the cost associated with this $872,000 credit is assigned directly to Rate Schedule ISA, which effectively means that it is assigned directly to the customer receiving the credit. The test year revenues for Rate Schedule ISA are reduced by the amount of the credit. Since there is no offsetting expense reduction, operating income before taxes is likewise reduced by the full amount of the credit. If rates are established in this proceeding at cost-of-service levels, the effect of the Company's methodology would be to require recovery of the full amount of this credit directly from the customer receiving the credit, thus <u>completing negating</u> the benefit of the credit. This clearly could not have been the intent of establishing the EDI program. Although the impact on other rate classes is diluted by the fact that each and every customer on the rate schedule (in which the cost of the credit is assigned) does not receive credits, the same basic flaw in the

Company's methodology is apparent. For example, under the Company's methodology, other LP-5 ratepayers must pay the costs associated with the approximate $13 million of economic development credits assigned to LP-5. Everything else being equal, under a cost-of-service ratemaking philosophy, this would dictate that all LP-5 customers are responsible for the economic development credits provided to some LP-5 customers. This is unreasonable for a program designed to benefit the system, and all of PP&L's customers.

Q. What methodology would you recommend with respect to the cost-of-service treatment of EDI and IDI revenue credits?

A. A more reasonable approach to treating these credits within the Company's 12 CP cost-of-service study would be to allocate the total cost of these credits ($30.624 million for the retail jurisdiction) to all customer classes, including Rate Schedules LP-4, LP-5 and ISA. I believe that a rate base allocator would be the most appropriate means of assigning the cost of these credits to each rate schedule. Each rate schedule would then be assigned a proportionate share of the cost of these credits (including the rate schedules in which the customers actually receiving the credit reside), rather than having 100% of the cost of the credits assigned to only those rate schedules. I believe that this modification to the Company's cost-of-service study is necessary in order to remove a bias built into the Company's analysis. This bias effectively requires (specifically in the case of Rate Schedule ISA) that a customer to pay for the cost of the economic development credits which the customer is receiving. This could not possibly have been the intent of the Company's EDI program, and therefore the cost-of-service study should be revised accordingly.

Q. **How does your proposed adjustment for EDI and IDI credits compare to the analysis presented by the Company in Exhibit JMK-2, Section VII?**

A. In response to a settlement agreement approved by the Commission in Docket No. R-870600, the Company filed a 12 CP cost-of-service study without any EDI and IDI revenue credits. This study, presented in Section VII of Exhibit JMK-2, computes cost-of-service at present rates under the assumption that there were no EDI and IDI credits paid. Rate schedule revenues for each customer class containing customers receiving such credits were increased by the full amount of the credits. However, unlike the adjustment which I made to the Company's cost study, PP&L's analysis in Section VII did not include (or allocate) the cost of paying the credits. As per PP&L's interpretation of the settlement agreement, it simply ignored the existence of the credits. The analysis that I performed recognized the payment of the credits as a cost-of-service and allocated them to all retail rate classes.

Q. **Have you developed a revised 12 CP cost-of-service study reflecting the three modifications which you have just described?**

A. Baron Exhibit ___ (SJB-2) presents a summary of the 12 CP cost-of-service study incorporating the three modifications which I have previously described. As can be seen from the results on pages 1 and 2, the relative rate of return indices have shifted somewhat from those presented in the Company's 12 CP cost-of-service study. It should be noted that this study is identical to the Company's cost-of-service study except for the three changes which I have described. In particular, the overall Pennsylvania jurisdiction rate of return of 7.31% is identical, since all of the modifications that I discussed only impact the allocation of cost in the retail jurisdiction and do not change the jurisdictional allocation.

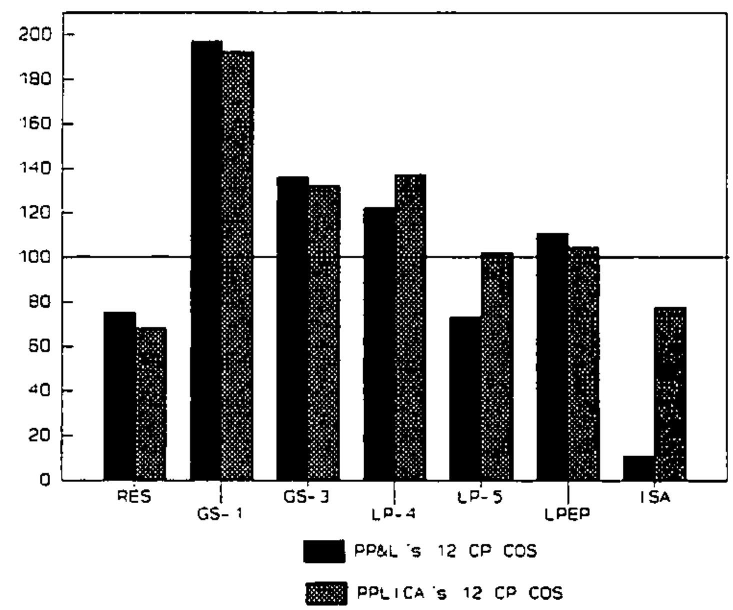
As can be seen from page 6 of Exhibit ___ SJB-2, the rate of return index for Rate Schedule LP-5 is 102.2, indicating that at present rates, LP-5 customers are earning slightly above the average system rate of return. This is an increase in the LP-5 relative rate of return compared to the Company's study. Similar increases also occur for Rate Schedules LP-4 and ISA. Principally, these three rate schedules contain customers receiving interruptible credits and EDI credits which were affected by the changes that I have made.

Q. How do the overall results compare with the Company's originally filed 12 CP cost-of-study for each rate class?

A. Figure 3 shows a comparison of the relative rate of return indices for the major rate classes between the Company's filed cost-of-service study and the PPLICA cost-of-service study that I am recommending in this proceeding. As can be seen, the relative rate of return indices, which indicate the relative position of a customer class vis-a-vis full cost-of-service, have changed modestly for most customer classes and more significantly for Rate Schedules ISA, LP-5 and LP-4. In particular, as I noted, under the PPLICA cost-of-service study, Rate Schedule LP-5 is providing a rate of return at present rates above the system average rate of return. As I will discuss below, the cost-of-service results shown in Baron Exhibit ___ (SJB-2), the PPLICA recommended cost-of-service study, should be employed to assign the increase granted in this proceeding to customer classes.

FIGURE 3

PP&L'S 12 CP COS VS. PPLICA'S 12 CP COS
CLASS RELATIVE RATE OF RETURN INDICES

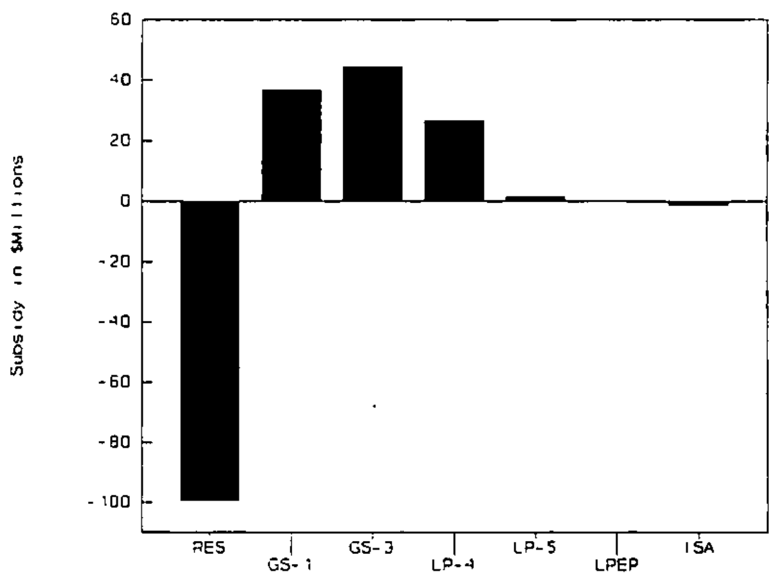


Q. Have you computed the subsidies received by various rate classes utilizing the results of your 12 CP cost-of-service study at present rates?

A. Yes. Figure 4 shows the subsidies received (a negative value) and the subsidies paid (a positive value) by each of the major rate classes, utilizing the results of the PPLICA 12 CP cost-of-service study. As can be seen from this graph, residential customers are receiving subsidies at present rates of almost $100 million. These subsidies are paid principally by Rate Schedules GS-1, GS-3 and LP-4. Rate Schedules LP-5, LPEP and ISA are neither paying nor receiving significant subsidies.

FIGURE 4

PPLICA'S 12 CP COS
INTERCLASS SUBSIDIES AT PRESENT RATES



Q. What does the subsidy analysis suggest with respect to the allocation of an increase granted by the Commission in this proceeding?

A. Together with the relative rate of return indices at present rates, the subsidy analysis shows the amount of revenue paid by certain rate classes to other rate classes in order to subsidize their electric service. Essentially, PP&L's smaller and medium commercial and industrial customers are paying close to $100 million to residential customers so as to reduce the cost of electricity to these residential customers. This should be reduced in a systematic manner in this proceeding so as to move all classes toward cost-of-service (considering gradualism and potential rate shock in the process) and reduce subsidies to the extent feasible in a single case.

IV. ALLOCATION OF COMMISSION-APPROVED REVENUE INCREASE TO RATE SCHEDULES

Q. Have you reviewed PP&L's proposed increases to each of its retail rate schedules as a result of its overall $262 million revenue increase request in this proceeding?

A. Yes. The Company is proposing to increase retail rate schedules by an average of 11.7%, after the effects of a proposed roll-in for the ECR, the elimination of the state tax adjustment surcharge, and a roll-in of a portion of the special base rate adjustment charge. This 11.7% average rate schedule increase represents the average increase on a customer's total bill, including all charges and credits.

Table 1 shows the percentage increases proposed by PP&L for each rate schedule. As can be seen, the total Pennsylvania retail jurisdiction is receiving an 11.7% increase. However, some rate schedules are receiving substantially greater increases than average. In particular, Rate Schedules LP-4 and LP-5 interruptible customers are receiving increases in the range of 27% to 34% on their total bills under PP&L's proposal. These increases are in the neighborhood of three times the system average increase which PP&L is proposing and represent the greatest increase to any rate schedule in this case.

TABLE 1

PENNSYLVANIA POWER & LIGHT COMPANY
SUMMARY OF PP&L'S PROPOSED
CLASS REVENUE INCREASES

RATE SCHEDULE	PRESENT REVENUE (w/roll-ins)	PROPOSED REVENUE	% INCREASE	$ INCREASE
RS	$886,748,156	$1,022.317.001	15.29%	$135,568,845
RTS	19,773,844	23,212,510	17.39%	3,438,666
RTD	363,891	416,266	14.39%	52,375
GS-1	161,735,899	167,996,786	3.87%	6,260,887
GS-3	506,985,301	541,081,324	6.73%	34,096,023
LP-4:				
LP-4, L4	267,879,730	290,306,487	8.37%	22,426,757
INTERRUPTIBLE	18,728,254	25,103,901	34.04%	6,375,647
ECO/IND	(13,254,820)	(14,273,227)	7.68%	(1,018,407)
LP-5:				
LP-5	148,535,286	162,231,436	9.22%	13,696,150
LP-6	32,506,451	34,367,438	5.72%	1,860,987
INTERRUPTIBLE	91,661,728	116,416,358	27.01%	24,754,630
ECO/IND	(13,090,615)	(13,292,954)	1.55%	(202,339)
LPEP	8,404,855	8,867,562	5.51%	462,707
ISA	20,448,546	20,480,185	0.15%	31,639
IS-1	186,035	189,472	1.85%	3,437
BL	480,920	524,346	9.03%	43,426
SA	4,292,175	4,866,903	13.39%	574,728
SM	1,618,482	1,839,857	13.68%	221,375
SHS	14,778,848	16,915,571	14.46%	2,136,723
SE	346,823	417,878	20.49%	71,055
TS(R)	54,756	61,980	13.19%	7,224
SI-1(R)	69,788	83,638	19.85%	13,850
GH-1(R)	36,095,375	41,918,917	16.13%	5,823,542
GH-2(R)	7,533,184	8,751,267	16.17%	1,218,083
STANDBY	1,148,211	1,156,092	0.69%	7,881
TOTAL PUC	$2,204,031,103	$2,461,956,994	11.70%	$257,925,891
OTHER REV	53,479,000	54,274,118	1.49%	795,118
ANN ADJ.	25,615,499	28,529,260	11.37%	2,913,761
FERC	483,916,000	483,916,000	0.00%	0
TOTAL OP REV	$2,767,041,602	$3,028,676,372	9.46%	$261,634,770

Q. Has PP&L presented this information in its filing with the Commission?

A. No. PP&L's proposed class revenue increases are presented in Exhibit OJK 1-4, the exhibit of PP&L witness Oliver J. Kasper. On page 4 of 4 of Section 3 of Mr. Kasper's exhibit, the overall increase in total class revenue is presented. It shows that the average LP-5 rate increase is 15.45%. Although, on average, this is correct for LP-5 customers, there are in fact three distinct groups contained within the LP-5 class: LP-5 firm customers, proposed LP-6 firm customers, and interruptible customers currently taking service on Rate Schedule LP-5. The Company does not present any information in its filing to indicate that interruptible customers on Rate Schedule LP-5 will receive a 27% overall increase under the Company's rate design proposals. A similar situation occurs on Rate Schedule LP-4.

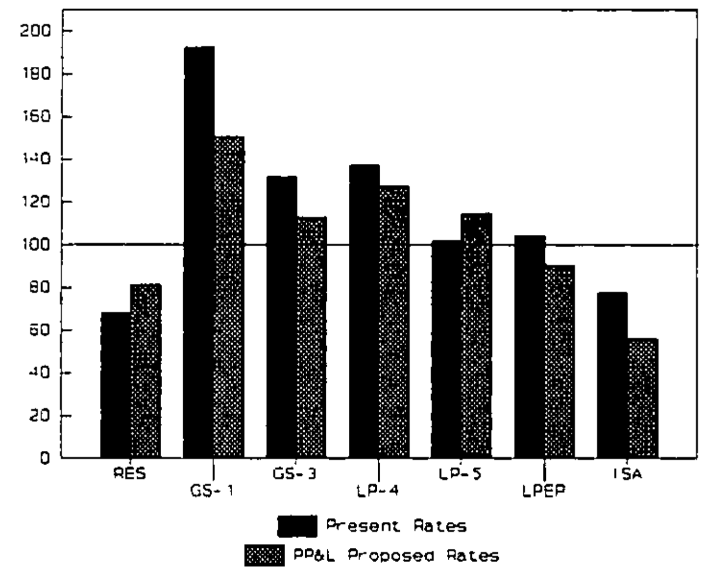
Q. Has the Company, at least on a total class basis (e.g., LP-5), attempted to move class rates toward cost-of-service?

A. Under PP&L's filed 12 CP cost-of-service study (which should not be used without the three modifications which I previously discussed), the Company has, for the most part, moved class rates of return toward the system average level. With the exception of Rate Schedule ISA, PP&L has increased its various rate schedules to make some movement toward cost-of-service, albeit not in a systematic fashion.

Figure 5 shows the rate of return indices using the PPLICA recommended cost-of-service study at present and PP&L-proposed rates. The cross-hatched bar graph for each rate schedule shows the rate of return index at PP&L-proposed rates. As can be seen, the Company's proposal does not produce a systematic movement toward cost-of-service. In particular, the residential class has been increased in a fashion such that the rate of return index still remains substantially below cost-of-service, <u>while the Company has increased rates for Rate Schedule LP-5 so that proposed rates exceed cost-of-service</u>.

FIGURE 5

**PPLICA'S 12 CP COS
RATE OF RETURN INDICES
PRESENT RATES VS. PP&L PROPOSED RATES**



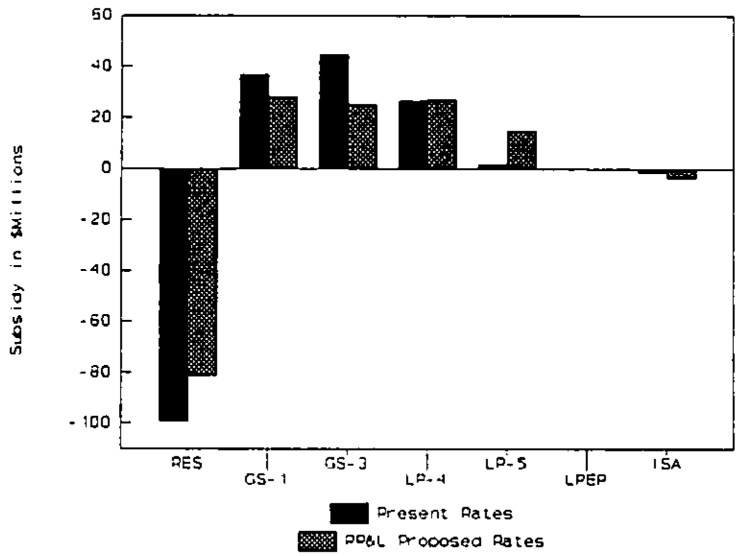
Q. Has PP&L addressed the cross-subsidies inherent in present rates?

A. Only slightly. Figure 6 shows a comparison of the interclass subsidies received by (a negative value) and paid by (a positive value) each of PP&L's major rate classes under present and proposed rates, again using the PPLICA modified 12 CP cost-of-service study.

As can be seen from this graph, PP&L's proposed increases continue to produce rates which are below cost-of-service for the residential class and continue to rely on substantial cross-subsidies from other rate schedules.

FIGURE 6

PPLICA'S 12 CP COS
COMPARISON OF INTERCLASS SUBSIDIES
PRESENT RATES VS. PP&L PROPOSED RATES



Q. Have you developed an alternative revenue allocation approach which relies on a more systematic movement of class rates toward cost-of-service?

A. Yes. I believe that a systematic approach that addresses the cross-subsidy issue directly and considers gradualism would produce class rate increases that are more in line with the goal of moving class rates toward cost-of-service.

Q. Would you describe the approach which you recommend the Commission employ in assigning the authorized rate increase to customer classes?

A. I recommend that the Commission establish class increases based on a goal of achieving a 50% reduction in existing subsidies for each rate class at proposed rates. The objective of this methodology is to reduce by 50% the dollar subsidies in proposed rates relative to the subsidies contained in present rates. This reduction in subsidies at proposed rates, utilizing the results of the cost-of-service study directly, systematically reduces cross-subsidies in a feasible manner. However, I also believe that it is appropriate to further adjust any rate schedule increases resulting from a 50% subsidy reduction criterion by a cap. The cap which I recommend in this proceeding is that no rate schedule, including the interruptible rate schedules, receive an increase in excess of 1.5 times the authorized system average increase. This consideration of the principle of gradualism is consistent with traditional ratemaking approaches. PP&L has also recognized this principle in its assignment of proposed increases to rate schedules, except for the interruptible rate schedules (L5I and L4I).

Q. Would you please describe the specific methodology which you recommend be employed to assign any revenue increases granted by the Commission to rate classes?

A. Baron Exhibit ____ (SJB-3) presents the results of the PPLICA-recommended methodology to reduce subsidies by 50% in proposed rates. Page 1 of 3 of Exhibit ___ (SJB-3) shows the current rate of return for each rate schedule, utilizing results of the PPLICA 12 CP cost-of-service study, at present rates. The left side of page 2 of 3 of Exhibit ___ (SJB-3) shows the increases necessary to equalize the rate of return for each rate class at present rates with the system average rate of return. As can be seen, without the Company receiving any increase, residential customers would need an 11% rate increase simply to move present rates to a cost-of-service level. At the same time, GS-1 customers would require a 23% rate decrease to set rate levels at cost-of-service.

This basic information is used in the analysis to develop the subsidies at present rates, which are to be reduced by 50% in proposed rates. The right side of page 2 of 3 of Exhibit ___ (SJB-3) shows the increases necessary to each rate schedule to produce the Company's requested overall revenue increase of $262 million in this proceeding.

The residential class would require an increase of 24.31% in order to produce the system average rate of return of 10.17% at proposed PP&L rate levels. Obviously, it is unrealistic to increase residential rates by this amount in a single case.

Page 3 of 3 of Exhibit ___ (SJB-3) shows the specific development of the proposed revenue increase (without any cap) in order to achieve a 50% subsidy reduction.[7] Column 3 of page 3 of 3 shows the current subsidies received by (a negative value) or paid by each rate class. The residential class is receiving a subsidy of $99.4 million at present rates. The objective of the PPLICA proposed methodology is to reduce this subsidy by 50% at proposed rates, subject to a "1.5 times systems average increase cap." As can be seen in Column 5, the subsidy for residential customers at proposed rates is set at $49.7 million. Following this methodology for each rate schedule produces the overall percentage increases shown in the last column. The end result is to increase rate schedule revenues by the same 11.7% requested by the Company (assuming that the Company actually received its entire rate request).

Q. Assuming that the Company did receive its entire $262 million rate increase request in this proceeding, do the increases shown on page 3 of Exhibit ___ (SJB-3) represent PPLICA's proposed increases for each rate class?

[7] This analysis is based on PP&L's requested $262 million increase. If the Commission authorizes a lower increase, as PPLICA is recommending, this analysis would be revised to reflect the actual increase. Future references to "proposed rates" in this testimony are also based on PP&L's requested increase level, for comparative purposes only.

A. No. As I indicated, I believe that it is appropriate to impose a constraint that no rate schedule shall receive an increase in excess of 1.5 times the system average increase in this proceeding. The Company is requesting a substantial revenue increase in this case and, given the relatively benign rate of current inflation in the United States of approximately 3%, the Company's proposed 11.7% increase itself is a substantial real price increase in a single case. As a result, I am recommending that a "1.5 times system average" cap be imposed on the increase to each rate schedule. Assuming PP&L receives its entire $262 million increase, this permits up to a 17.6% increase to each rate schedule requiring substantial movement toward cost-of-service. Again, given that U.S. inflation is at a 3% level, a 17.6% increase in a single case is still substantial.

Q. Based on the results shown on page 3 of Exhibit __ (SJB-3), some rate schedules (e.g., GS-1) should receive a rate decrease under your recommended "50% subsidy reduction" approach. Are you recommending a decrease for any rate schedule in this proceeding?

A. No. Although, based on a strict cost-of-service basis, Rate Schedule GS-1 should receive a decrease, I believe that proposing a "0" increase to such a rate class is a reasonable ratemaking approach. As such, I am recommending that no rate schedule receive a decrease in this proceeding.

Baron Exhibit ___ (SJB-4) shows the development of the PPLICA recommended rate schedule increases (at PP&L's $262 million revenue increase level), utilizing a cost-of-service criteria (the proposed 50% subsidy reduction), together with a limitation that no rate class receives an increase in excess of 1.5 times the system average increase. Resulting increases are shown in the last column of Exhibit ___ (SJB-4). These increases are derived from the cost-of-service based increase shown on page 3 of Exhibit ___ (SJB-3), adjusted to remove any excess increase over and above 1.5 times the system average increase. In addition, the revenue decreases which a cost-of-service based approach would dictate for certain rate classes such as GS-1, have been eliminated in the overall recommended increases shown on Exhibit ___ (SJB-4). Assuming that the Company received its entire $262 million rate request, the recommended percent increases shown in Exhibit ___ (SJB-4) should be utilized by the Commission in this proceeding. These increases are summarized in Table 2, on the following page. As can be seen, the residential class, the LP-4 interruptible schedule and the LP-5/LP-6 interruptible schedule are all receiving increases at the capped amount of 17.6%. In addition, a number of other rate classes are also receiving increases at the capped amount. Finally, the recommended increase for Rate Schedule ISA is 15.98%, substantially greater than the .15% proposed by the Company. PP&L has indicated that its contract with its customer would limit the increase to 0.15%. I have not made any assessment of this contract issue. If the Commission chooses to implement the Company's proposal as a result of contract considerations, an adjustment would be necessary to implement such a Commission authorized constraint to the increase to Rate Schedule ISA.

Of course, these increases are based on the Company's full $262 million rate request. If the Commission authorizes a lower increase, as recommended by PPLICA, the increases shown on Table 2 would have to be adjusted.

TABLE 2

PENNSYLVANIA POWER & LIGHT COMPANY
SUMMARY OF CLASS REVENUE INCREASES
USING COST-OF-SERVICE CRITERIA
RECOMMENDED BY PPLICA*

RATE SCHEDULE	PRESENT REVENUE (w/roll-ins)	$ INCREASE	% INCREASE
RS	$886,748,156	$155,624,301	17.55%
RTS	19,773,844	3,470,310	17.55%
RTD	363,891	63,863	17.55%
GS-1	161,735,899	0	0.00%
GS-3	506,985,301	37,587,935	7.41%
LP-4:			
LP-4, L4C	267,879,730	15,016,205	5.61%
INTERRUPTIBLE	18,728,254	3,286,809	17.55%
ECO/IND DEV CR	(13,254,820)	(1,018,407)	7.68%
LP-5:			
LP-5	148,535,286	10,822,489	7.29%
LP-6	32,506,451	1,626,705	5.00%
INTERRUPTIBLE	91,661,728	16,086,633	17.55%
ECO/IND DEV CR	(13,090,615)	(202,339)	1.55%
LPEP	8,404,855	879,361	10.46%
ISA	20,448,546	3,268,424	15.98%
IS-1	186,035	13,793	7.41%
BL	480,920	0	0.00%
SA	4,292,175	753,277	17.55%
SM	1,618,482	284,044	17.55%
SHS	14,778,848	2,593,688	17.55%
SE	346,823	60,867	17.55%
TS(R)	54,756	9,610	17.55%
SI-1(R)	69,788	12,248	17.55%
GH-1(R)	36,095,375	6,334,738	17.55%
GH-2(R)	7,533,184	1,322,074	17.55%
STANDBY	1,148,211	0	0.00%
TOTAL PUC	$2,204,031,103	$257,896,628	11.70%
OTHER REV	53,479,000	795,118	1.49%
ANN ADJ.	25,615,499	2,913,761	11.37%
FERC	483,916,000	0	0.00%
TOTAL OP REV	$2,767,041,602	$261,605,507	9.45%

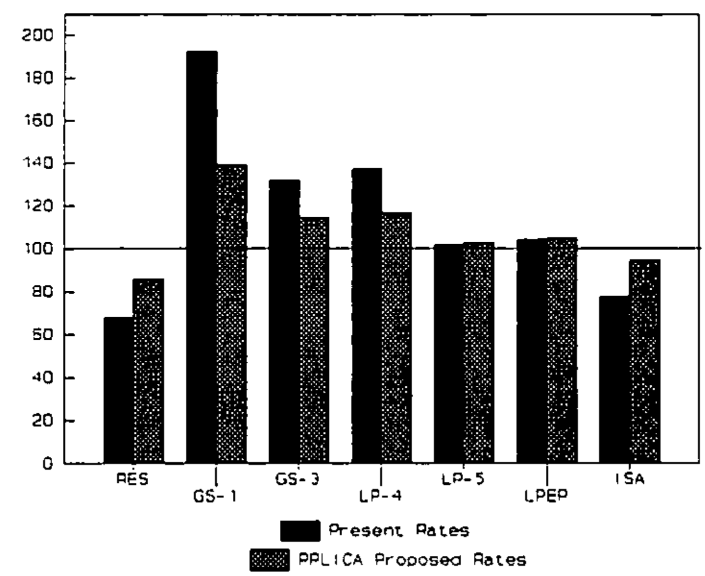
* The results in this table are based on the assumption that PP&L receives its entire $262 million increase. If the Commission authorizes a lower increase, as recommended by PPLICA, the results shown should be adjusted to reflect actual authorized increase.

Q. Have you calculated the rate of return indices at proposed PPLICA rates (assuming the Company receives its entire rate request)?

A. Yes. Figure 7 shows a comparison of present PP&L rates vs. proposed rates under the PPLICA recommended distribution of increases shown in Table 2 of my testimony. As can be seen, rate of return indices at proposed rates moved toward 100. This reflects a systematic movement toward cost-of-service, while recognizing a constraint that no rate schedule receives an increase more than 1.5 times the system average increase.

FIGURE 7

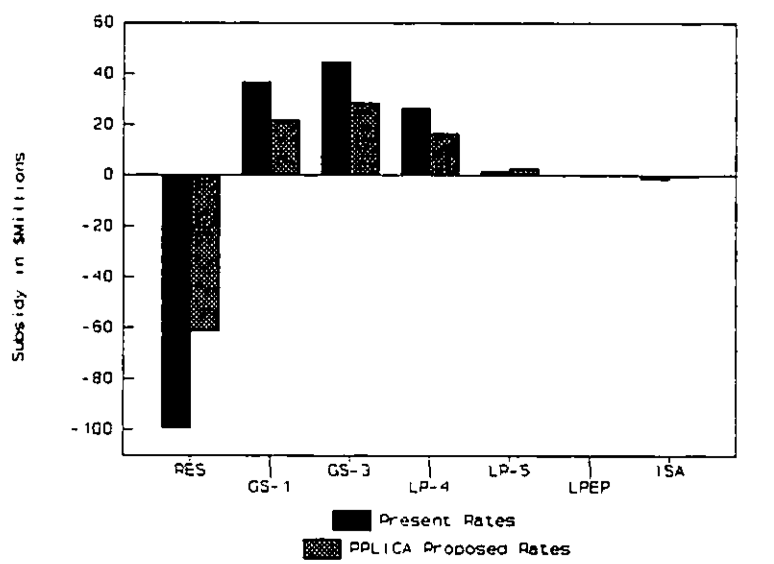
PPLICA'S 12 CP COS
COMPARISON OF RATE OF RETURN INDICES
PRESENT RATES VS. PPLICA PROPOSED RATES



More significantly, the proposed subsidies under the PPLICA-recommended distribution of the Company's requested $262 million increase reflect a substantial movement toward subsidy reduction. Although a complete 50% subsidy reduction (from the level contained in present rates) is not achieved due to the "1.5 times constraint," the PPLICA proposal does make a substantial movement toward cost-of-service. Figure 8 shows a comparison of the dollar subsidies contained in present and proposed rates under the PPLICA-recommended distribution of the increase. As can be seen, residential subsidies drop to approximately $60 million from close to $100 million at present rates. For those classes who are paying subsidies, those subsidy payments are reduced at proposed rates.

FIGURE 8

PPLICA'S 12 CP COS
COMPARISON OF INTERCLASS SUBSIDIES
PRESENT RATES VS. PPLICA PROPOSED RATES



Q. All of the analyses which you have discussed thus far assume that the Company receives its entire requested increase of $262 million. Do you have any recommendations to the Commission regarding a distribution of increases to rate schedules for an authorized increase less than $262 million?

A. My specific recommendation is to use the relative dollar increases shown in Table 2 as a means of distributing any authorized increase in this proceeding. Table 3 shows an example of the application of this approach, assuming that the Company received a $20 million increase in this case, an increase approximating the PPLICA revenue requirement recommendation. As in my overall recommendation shown in Table 2, for those rate classes receiving no increase at $262 million overall PP&L increase, I would again recommend that no increases be applied if the Company receives a lesser amount of revenue increase in this proceeding. Baron Exhibit ____(SJB-5) shows a detailed calculation of these increases, assuming that the Company received an overall revenue increase of $20 million in this proceeding

TABLE 3

PENNSYLVANIA POWER & LIGHT COMPANY SUMMARY OF PROPOSED CLASS REVENUE INCREASES ASSUMING $20 MILLION AUTHORIZED RATE INCREASE

RATE SCHEDULE	PRESENT REVENUE (w/roll-ins)	RECOMMENDED $ INCREASE @ $20 Million	RECOMMENDED % INCREASE @ $20 Million
RS	$886,748,156	$12,138,646	1.37%
RTS	19,773,844	270,683	1.37%
RTD	363,891	4,981	1.37%
GS-1	161,735,899	0	0.00%
GS-3	506,985,301	2,931,847	0.58%
LP-4:			
LP-4, L4C	267,879,730	1,171,259	0.44%
INTERRUPTIBLE	18,728,254	256,370	1.37%
ECO/IND DEV CR	(13,254,820)	(1,018,407)	7.68%
LP-5:			
LP-5	148,535,286	844,151	0.57%
LP-6	32,506,451	126,882	0.39%
INTERRUPTIBLE	91,661,728	1,254,752	1.37%
ECO/IND DEV CR	(13,090,615)	(202,339)	1.55%
LPEP	8,404,855	68,590	0.82%
ISA	20,448,546	254,936	1.25%
IS-1	186,035	1,076	0.58%
BL	480,920	0	0.00%
SA	4,292,175	58,755	1.37%
SM	1,618,482	22,155	1.37%
SHS	14,778,848	202,307	1.37%
SE	346,823	4,748	1.37%
TS(R)	54,756	750	1.37%
SI-1(R)	69,788	955	1.37%
GN-1(R)	36,095,375	494,108	1.37%
GN-2(R)	7,533,184	103,121	1.37%
STANDBY	1,148,211	0	0.00%
TOTAL PUC	$2,204,031,103	$18,990,326	0.86%
OTHER REV	53,479,000	795,118	1.49%
ANN ADJ.	25,615,499	214,556	0.84%
FERC	483,916,000	0	0.00%
TOTAL OP REV	$2,767,041,602	$20,000,000	0.72%

V. LP-5 RATE DESIGN ISSUES

Q. **Would you please summarize the Company's proposals for LP-5 and LP-6 rate design in this case?**

A. Under the Company's proposal, there are essentially four different rate schedules contained within the LP-5 revenue class: LP-5, LP-5 interruptible, LP-6, and LP-6 interruptible. Although the Company has historically identified a single LP-5 revenue class for cost-of-service and other purposes, the current LP-5 tariff actually includes two separate and distinct rate schedules. The first of these is the LP-5 firm schedule; the second is the interruptible rate schedule identified as LP-5I. Although both schedules appear on the same tariff sheet, they are completely different rates. For example, the current LP-5 demand charge is $4.39 per kW, while the current LP-5 interruptible demand charge is $9.60 per kW. Similar differences appear with respect to the hours use blocking in the rate, as well as in the kWh charges in the two rates. Essentially, these are two different rate schedules providing service to two different types of large power customers.

In its proposal in this case, PP&L has introduced an additional firm rate schedule and an additional interruptible rate schedule for customers whose average demand exceeds 10,000 kWs (subject to some additional considerations). In addition, the Company has eliminated the separate interruptible tariff (which was part of the LP-5 rate schedule) and has instead substituted an interruptible credit applied to firm rates (both LP-5 and LP-6) in its place. Under the Company's proposal, there will be four different LP-5/LP-6 rates, all under the LP-5 revenue category. In the Company's presentation in this case, the overall LP-5 revenue increase is shown to be 15.45%, compared to the overall system average increase of 11.7%. However, as can be seen in Table 1 of my testimony, when the LP-5 revenue class is disaggregated into LP-5 firm customers, LP-6 firm customers, and interruptible customers, the increases vary significantly from the average 15.45% overall LP-5 increase.

Interruptible customers, taking service on the Company's proposed LP-5 and LP-6 interruptible schedules, will receive increases on average of 27%, compared to the average LP-5 increase of 15.45% and the average overall increase of 11.7% for all rate schedules. The Company's testimony and exhibits in this case did not present these results for the interruptible customers on Schedule LP-5.

Realistically, there are at least four separate and distinct rate schedules contained in the LP-5/LP-6 revenue group. While this is an appropriate basis for analyzing proposed rate design in this case, <u>PPLICA is recommending three separate and distinct rate schedules: LP-5 firm, LP-6 firm, and LP-5/LP-6 interruptible</u>.

Q. Have you analyzed the development of the Company's proposed LP-5 firm and LP-6 firm rate schedules?

A. Yes. My review of these two proposed firm rate schedules indicates that the Company's basic design is reasonable. However, I do recommend that the revenue increases shown in Table 2 of my exhibit (PPLICA-recommended increases at the full PP&L $262 million increase level) be utilized to establish the revenue requirements for each of these two firm schedules. As I previously discussed, the PPLICA approach is designed to reflect cost-of-service in a systematic fashion, while recognizing a 1.5 times revenue constraint to any single rate schedule.

Q. What is your recommendation regarding PP&L's proposed interruptible rate design for LP-5 and LP-6 customers?

A. First, as shown in Table 2 of my testimony, I am recommending that the overall LP-5/LP-6 interruptible rate be increased by 1.5 times the system average increase granted by the Commission in this proceeding. This is a substantial increase relative to the proposals which I am making with respect to LP-5 and LP-6 firm rates and reflects the Company's objective of substantially reducing the interruptible credit following this case. However, I believe that it is essential to limit the increase to these interruptible customers to the 1.5 times the system average cap, as I have recommended for other rate schedules, including residential customers.

Q. Based on your recommendation for an interruptible increase of 1.5 times the system average increase, what is your recommendation regarding the specific interruptible rate design?

A. I believe that it is appropriate to retain the existing LP-5 interruptible rate structure in this proceeding. The Company's proposed interruptible credit approach (a credit to firm rates for interruptible load) is simply one alternative form of interruptible rate design. The Company's current interruptible rate is another form which can be used, regardless of the level of interruptible credit implied in the rate. Since I am recommending an increase to LP-5 interruptible rates in this proceeding capped at 1.5 times the system average increase, the most logical methodology to implement this increase is to apply the percentage increase directly to the existing LP-5 interruptible rate design. Essentially, my proposal would entail increasing each of the rate elements (e.g., demand charge, energy charges) by the percentage increases necessary to achieve the overall revenue increase for these interruptible customers of 17.55%, assuming that the Company received its entire increase. This approach of continuing to utilize the existing interruptible rate structure facilitates the revenue increase proposal that I am recommending. The Company's proposed fixed interruptible credit would violate the principle of gradualism and prevent the implementation of the "1.5 times" capping methodology.

Finally, I am recommending that the current interruptible rate structure continue to be identical for both LP-5 and new LP-6 customers, adjusted to reflect the increases that I am recommending in this proceeding.

Q. Have you designed an LP-5, an LP-6, and an interruptible rate to reflect your revenue increase and rate design recommendations?

A. Yes. Baron Exhibit ___ (SJB-6) shows the proposed PPLICA rate design, under the assumption that the Company is authorized its overall $262 million increase. These rates reflect the increases shown in Table 2 of my Exhibit, which is the PPLICA revenue increase distribution proposal. Page 1 of Exhibit ___ SJB-6 summarizes the proof of revenue analysis at present and proposed rates for the overall LP-5 revenue class. Under the PPLICA proposal at PP&L's full $262 million increase level, the LP-5 revenue class would receive a 10.9% increase. This reflects the cost-of-service based approach that I have previously discussed. Pages 2 and 3 of Exhibit ___ SJB-6 show the proposed LP-5 firm, LP-5 interruptible, LP-6 firm, and LP-6 interruptible rates. It should be noted that the LP-5 interruptible and LP-6 interruptible rates are identical, as per my previous discussion. Therefore, under this proposal there is a <u>single</u> interruptible rate for LP-5/LP-6 customers.

Q. Under the approach that you are recommending in this proceeding to apply a revenue increase to the existing LP-5 interruptible rate schedule, there is no

specifically stated interruptible credit inherent in the rate. Is there an "implied" interruptible credit under your rate design?

A. Yes. The proposed interruptible rate for LP-5 and LP-6 customers that I am recommending does not explicitly identify an interruptible credit from an otherwise firm rate schedule. However, such an analysis can be developed by simply rebilling all of the LP-5 interruptible and LP-6 interruptible billing determinants at the PPLICA-proposed LP-5 and LP-5 firm rates. This analysis would establish the overall revenue paid by these interruptible customers under the firm tariffs that PPLICA is recommending and thus provide a basis to compute the "implied interruptible credit" inherent in my recommended interruptible rate.

Under the PPLICA methodology, we have maintained the relationship between LP-5, LP-6, and interruptible customers in a fashion similar to the original distribution of increases within the LP-5 revenue class proposed by the Company. As a result, the interruptible credit inherent in the PPLICA interruptible rate design is approximately the same as that proposed by the Company.

VI. INTERRUPTIBLE RATE ISSUES

Q. One of the specific issues to be addressed in this proceeding concerns the cost and value of interruptible load on the PP&L system. Do you agree with the Company's proposed "resource value" approach to developing interruptible rates?

A. No. I should note that the PPLICA recommendations in this proceeding are, to a large extent, governed by the Company's filing with respect to cost-of-service and the relative increases within the LP-5 revenue class. As I discussed previously, however, I have continued to reflect the relative increases within the LP-5 revenue class to LP-5 firm, LP-6 firm, and LP-5/LP-6 interruptible customers proposed by PP&L.

The Company has proposed to utilize what I call a "resource value" approach to developing an interruptible credit, which basically assumes that interruptible load is a substitute for peaking capacity. Under the Company's proposal, interruptible customers would be priced at firm service rates less a credit equal to the value such customers provide on an equivalent peaking capacity basis to the PP&L system. Under this approach, interruptible customers would be paying rates based on "value," while all other PP&L customers would be paying rates based on embedded costs.

Q. Could you please explain this concept further?

A. PP&L is assuming, for the purposes of evaluating and developing its interruptible rate in this proceeding, that interruptible load is a peaking resource and reflects the value of combustion turbine capacity (or some other measure of the "value" of peaking capacity). This is reflected in the Company's cost-of-service study as a $300 per kW reduction for interruptible load from plant-in-service. Inherent in the Company's methodology is an assumption that interruptible load on the PP&L system is a <u>resource to be purchased</u> by the Company, rather than a low reliability load to be served by the Company. This is a significant feature of the Company's resource value approach to interruptible rate design, compared to a traditional cost-of-service approach, which recognizes the lower cost associated with serving low reliability interruptible power.

I do not believe that there is a justification for treating interruptible sales in a different manner from other sales. Such customers, in my opinion, are entitled to cost-of-service based rates, rather than being subjected to prices established based on the cost of the latest CT available to PP&L, or, perhaps, the revenues received from capacity credit sales. Both of these approaches (PP&L's CT cost valuation or a PJM capacity credit sale valuation) reflect a market-based approach that is inherently discriminatory to interruptible customers who desire to purchase lower quality power.

The question the Commission must decide is whether interruptible customers are entitled to the same pricing basis as afforded other customers on the PP&L system, or whether they should be subjected to alleged market-based considerations under the assumption that these interruptible customers are actually selling capacity to PP&L. Essentially, under the PP&L's framework, interruptible customers who desire to purchase lower quality power are being told that they are in effect buying firm power but are also selling peaking capacity to PP&L. Since the interruptible customers must sell their "capacity" to PP&L, the Company is a monopsonist in these transactions.

Q. Setting aside the policy implications of discriminatory treatment of interruptible customers, are there any other problems with PP&L's specific approach?

A. Yes. First, as I will discuss, PP&L's valuation of interruptible load is incorrect since it fails to include a PP&L adjustment for active load management, which essentially raises the value of interruptible load to reflect a reserve margin which is avoided in addition to the basic capacity, when interruptible load is on the system. This ALM adjustment increases the capacity value of each kW of interruptible load by a factor of 1.19. PP&L includes interruptible load in its PJM capacity at a rate of 1.19 kW of capacity for each kW of interruptible load. PP&L relies on this ALM to adjust interruptible load in its resource plans. Clearly, the capacity equivalent value of interruptible load should reflect this adjustment. If the Commission were to adopt PP&L's treatment of interruptible load contained in its cost-of-service study, the $300 per kW "value" should be increased to $357 per kW to reflect the 1.19 ALM factor.

Q. Are there other measures of resource value that could reflect interruptible load value?

A. Yes. There is an alternative measure of resource value, assuming that were the proper basis for an interruptible rate. The official PJM capacity deficiency rate of $73 per kW year is a measure of the value of interruptible load on the PP&L system. As shown in Table 4, this PJM capacity deficiency rate should also be adjusted by the ALM factor to arrive at an equivalent value for interruptible load. As can be seen from the table, the annual value of capacity using the PJM capacity deficiency rate is $86.87 per kW year, or <u>$7.24 per kW month</u>. This would be a more accurate "resource value" for interruptible loads than the value assumed by PP&L, since it represents an unbiased agreement among PJM members as to the official cost of deficiencies with respect to PJM capacity.

<u>TABLE 4</u>

PJM CAPACITY DEFICIENCY RATE

	$73.00	(PJM Rate)
x	1.19	Active Load Management Factor
	$86.87	per kW Year
	$ 7.24	per kW Month

Q. You previously indicated that you did not agree with a "resource value" approach to developing a proper interruptible rate. What approach would you recommend to the Commission to utilize in this proceeding to develop an appropriate interruptible rate for PP&L's largest customers?

A. First, as I previously discussed, I am recommending that a specific increase be applied to the existing interruptible rate for LP-5 and LP-6 customers, equal to 1.5 times the system average increase.

Second, I believe that an appropriate interruptible rate should be based on cost-of-service principles so that interruptible customers face the same pricing and costing mechanism and framework used to establish rates for other customer classes. There is simply no basis for assuming that an interruptible customer who must sell capacity to PP&L (under PP&L's theory) should be required to do so under monopsonist conditions (i.e., a sole purchaser in the market). If industrial customers were permitted to sell their capacity resources to other utilities or to other retail customers, there may be more reason to warrant a resource value approach for interruptible load. In addition, of course, if industrial customers were free to purchase electricity from other utilities, there would be no specific concern with the methodology utilized by PP&L to establish an interruptible credit. Unfortunately, neither of these two circumstances exists.

PP&L is a monopsonist with respect to purchasing peaking capacity resources from its industrial customers. As such, it is inappropriate to utilize a resource value approach in ratemaking. Rather, interruptible customers should be considered as all other customers on the system are considered. It is necessary to establish a cost-of-service basis for pricing electricity to low reliability interruptible customers. Such a cost-of-service analysis cannot rely on a combination of firm rates established through embedded cost pricing and interruptible credits established through a marginal cost or market-based approach. This latter method is exactly what PP&L has done in this proceeding, and it should be rejected.

The appropriate approach is to establish an interruptible credit based on a cost-of-service principle. The principle that I have relied upon in previous cases in Pennsylvania and elsewhere is to establish the interruptible credit based on at least a 50% discount off the total production demand cost per kW for the industrial class. This 50% or greater production demand discount recognizes that interruptible customers' loads are not included in the PP&L resource plans, and, thus, in the long run, that no production capacity is planned or constructed for these customers. It also recognizes that, to the extent that PP&L's industrial tariff constrains interruptions to 200 hours per year, some measure of fixed production demand costs may be assignable to these interruptible customers. A production demand discount of at least 50%, in my opinion, represents a reasonable basis to establish the cost-of-service associated with serving large industrial interruptible customers.

Q. Have you developed such a "production demand discount"-based interruptible rate credit?

A. Yes. Baron Exhibit ___ (SJB-7) shows the development of the production demand revenue requirements associated with LP-5 customers, based on the PPLICA 12 CP cost-of-service study, at the requested 10.17% rate of return.

As can be seen from Exhibit ___ (SJB-7), the overall LP-5 production demand revenue requirement at the Company's requested 10.17% rate of return is $166.975 million. Table 6 shows the development of an appropriate cost-of-service based interruptible credit using this product demand revenue requirement. The table develops the overall production demand unit cost for PP&L's LP-5 class. This revenue requirement, when unitized by LP-5 billing kW (firm and interruptible), produces an overall production demand cost per kW of $16.72. Fifty percent of this value is <u>$8.36 per kW</u> per month, which represents, in my opinion, a reasonable cost-of-service based interruptible credit. It somewhat exceeds the resource value credit of $7.24 that I previously developed using the PJM capacity deficiency rate.

TABLE 5

CALCULATION OF COST-OF-SERVICE BASED INTERRUPTIBLE CREDIT

LP-5 Production Demand	$166,957,000
Revenue Requirements @ 10.17% ROR	
LP-5 Billing kW (Firm and Interruptible)	9,986,262
LP-5 Production Demand Cost per kW	$16.72 per kW
50% Production Demand Discount	$8.36 per kw

Q. Are you recommending that the interruptible rate be established in this proceeding using an $8.36 per kW credit?

A. No. Although I believe that this approach is an appropriate method to arrive at an interruptible credit, the specific recommendation I am making in this proceeding is to increase the interruptible rate by an amount equal to one and half times the system average increase granted to PP&L. This recommendation produces a result which reasonably considers the principle of gradualism that both PP&L and I support. The resulting "implied" interruptible credit is less than the $8.36 per kW cost-of-service based credit.

Q. Does this complete your testimony on rate structure and cost-of-service issues?

A. Yes.

VII. ENERGY COST RATE ISSUES

Q. Would you briefly summarize the energy cost rate issues which you will address in this section of your testimony?

A. PP&L is proposing (witness Kleha) to establish an automatic mechanism within the ECR to recover revenue requirements associated with the termination of the Company's 945 mW capacity sale to JCP&L. Beginning on January 1, 1996, this 945 mW sale of capacity to JCP&L will phase out in equal 189 mW increments over a five-year period. The Company is proposing to modify its ECR to automatically increase retail rates to recover the lost revenues which it otherwise would have recovered from JCP&L. The test year level of revenue requirements associated with the JCP&L sale are estimated by PP&L to be $177.6 million. This represents the revenue requirements (non-energy-related) associated with the entire 945 mW sale. Under the Company's proposal, it will include $35.5 million of this revenue requirement amount in its January 1, 1996 ECR calculation. Subsequently, on January 1, 1997, the Company would include an additional $35.5 million of expense in its ECR. At the end of five years, the total estimated expense to be included in the ECR would be $177.6 million.

In addition to this JCP&L revenue requirement adjustment, PP&L is also proposing to include the full amount of off-system sales related to capacity credit sales to PJM companies, output reservation sales, and transmission entitlement sales. During the test year, the retail portion of these sales amounted to approximately $20.8 million. The Company has filed its rates in this proceeding under the assumption that it would include the full amount of such capacity-related sales revenues in its ECR as a credit to ECR fuel and purchased power costs. Ordinarily, these capacity-related revenue credits would be included as a base rate item, offsetting other revenue requirements.[8]

Finally, the Company has stated that it would not include these capacity-related sales revenues in the ECR unless it obtains approval for its proposal to include the revenue requirements from the returned JCP&L capacity within the ECR as well. The Company's reasoning on this appears to be that future levels of off-system capacity-related sales will be made possible by the return of JCP&L capacity. As such, the Company argues that it should only have to pass on these capacity credit sales if it also is entitled to recover the revenue requirements associated with the returned JCP&L capacity.

Q. Do you agree with the Company's proposal to include, as an expense within the ECR the revenue requirements associated with the returned JCP&L capacity?

[8] As a settlement to Docket No. M-00930406, one-third of the PJM capacity credit revenues are currently being credited within the ECR. Since none of these revenues are included as a credit to base rates, PP&L is retaining for its stockholders two-thirds of these PJM capacity credit revenues and 100% of output reservation sales and transmission entitlement sales revenues.

A. No. The Company's proposal is totally unreasonable. PP&L is requesting that this Commission grant it an automatic rate increase <u>today</u> of $35.5 million per year for each of the next five years (totaling $177.6 million by the year 2000) as a result of a lost wholesale transaction. The Company's proposal is not supported by any reasonable ratemaking principle since it amounts to a single issue rate case and does not consider any potential offsetting expenses, revenues, or other factors which may negate such an increase.

The revenue requirement associated with the generating capacity being sold currently (and in the test year) to JCP&L is not at issue in this base rate proceeding. The Company has correctly allocated these revenue requirements to its wholesale jurisdiction. As such, retail ratepayers are not responsible for these costs under a traditional test year ratemaking approach. PP&L's proposal is designed to eliminate the requirement that the Company file a full test year cost-of-service analysis which considers all investment, revenues, and expenses. Rather, PP&L is seeking from this Commission the authority to automatically increase retail rates whenever a wholesale power contract is terminated. This is an unprecedented request and should be rejected by the Commission.

Q. If the Commission accepts your recommendation to reject PP&L's proposal, what options does PP&L have to deal with its lost revenues from JCP&L?

A. The Company has two options. First, it can sell the capacity to some other utility or entity and replace the lost revenues, in which case it is no worse off than had it continued selling the capacity to JCP&L (assuming it achieves the same price). Second, PP&L can file a retail rate case in Pennsylvania if it believes it is not earning a fair rate of return on its prudent, used and useful investment. The Company would have the burden-of-proof to establish that this "returned" generating capacity (the 945 mWs currently being sold to JCP&L) is <u>used and useful</u> and should be recovered by retail ratepayers. In addition, PP&L would have the burden-of-proof to establish that it has a <u>revenue requirement deficiency</u> as a result of the lost JCP&L sales.

Q. Does this mean that PP&L should be entitled to retain any capacity-related revenues which it receives as a result of selling all or part of the 945 mWs of JCP&L "returned" capacity to other parties?

A. Yes. Since I believe that it is inappropriate to automatically recover the costs associated with the "returned" 945 mWs of capacity from retail ratepayers without a retail rate case, I also believe that it is appropriate for PP&L to retain any revenues directly attributable to the freeing-up of this capacity as a result of no longer selling all of part of it to JCP&L. As such, I agree with PP&L's proposal that capacity credit and other capacity-related sales <u>directly attributable to the incremental capacity</u>

freed-up from the sale to JCP&L be retained by the Company and not passed on to customers through the ECR.

Q. Do you believe that it is appropriate, in this proceeding, to include the $22 million of test year capacity credit, output reservation, and transmission entitlement revenues within the ECR?

A. No. It is appropriate to include the $22 million (with GRT) of capacity credit, output reservation, and transmission entitlement revenues ("other revenues") as a base rate offset to revenue requirements in this proceeding. As I previously discussed, the Company has filed this case under the assumption that these capacity-related credits are included within the ECR. My recommendation is to include the fixed, test year level of these revenue credits within base rates and remove them from the ECR. This is consistent with the Company's position that if the proposed automatic adjustment mechanism for its JCP&L capacity take-back is rejected by the Commission, capacity credit revenues should be excluded from ECR treatment. However, the test year level of these capacity-related revenue credits should be included as an offset to revenue requirements within base rates. PPLICA's recommendation to include these off-system revenue credits in base rates does not change, regardless of the Commission's ultimate disposition of the Company's JCP&L request.

Q. Does this complete your testimony?

A. Yes.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

PP&L INDUSTRIAL CUSTOMER ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

APRIL 1995

Expert Testimony Appearances
of
Stephen J. Baron
As of March 1995

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates,excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa Clara	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

Expert Testimony Appearances
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Stephen J. Baron
As of March 1995

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

Expert Testimony Appearances
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As of March 1995

Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.

Expert Testimony Appearances of Stephen J. Baron As of March 1995

Date	Case	Jurisdict.	Party	Utility	Subject
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load forecasting.

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As of March 1995

Date	Case	Jurisdict.	Party	Utility	Subject
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.

Expert Testimony Appearances
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Stephen J. Baron
As of March 1995

Date	Case	Jurisdict.	Party	Utility	Subject
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co.	Analysis of South Central Bell's restructuring and and proposed merger with Southern Bell Telephone Co.
12/91	91-410- EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.

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Stephen J. Baron
As of March 1995

Date	Case	Jurisdict.	Party	Utility	Subject
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger of GSU into Entergy System; impact on system agreement.
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.

Expert Testimony Appearances
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Stephen J. Baron
As of March 1995

Date	Case	Jurisdict.	Party	Utility	Subject
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	3905-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95 Answer	941-430EG Phase II Testimony	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates.

PPL/CA Adjusted 12 CP Cost-of-Service Study
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Summary

	Input	Allocation	Output	Total Pennsylvania Jurisdiction	RS	RTS	GS-1	GS-3	LP-4
Rate Base									
Plant-in-Service									
Production			P10	5,021,440	1,927,589	91,807	253,326	1,154,196	653,902
Transmission			P20	365,607	140,881	6,710	18,515	84,356	47,792
Distribution			P30	2,532,998	1,477,443	55,187	198,276	409,887	137,807
Other			POT1	276,661	137,175	4,985	17,476	51,027	26,539
Common Plant (Acct. 186)			P97T	0	0	0	0	0	0
Total Plant-in-Service			P00	8,196,706	3,683,087	158,689	487,594	1,699,466	866,038
Depreciation Reserve									
Production			A10	1,396,759	536,176	25,537	70,465	321,050	181,889
Transmission			A20	116,155	44,759	2,132	5,882	26,800	15,184
Distribution			A30	867,290	508,263	18,327	68,041	134,377	44,785
General Plant			A88	89,267	44,261	1,608	5,639	16,464	8,563
Intangible Plant			A95	7,651	3,794	138	483	1,411	734
Total Depreciation Reserve			AOST	2,477,122	1,137,252	47,743	150,510	500,103	251,154
Amortization Reserve			A97T	0	0	0	0	0	0
Total Depreciation & Amort. Reserve			A00	2,477,122	1,137,252	47,743	150,510	500,103	251,154
Total Net Plant in Service			P01	5,719,584	2,545,836	110,947	337,083	1,199,363	614,884
Total Subtractive Adjustment			PLEDE	903,062	372,752	16,894	49,505	198,752	107,580
Total Additive Adjustment			PLADD	12,378	4,752	226	624	2,845	1,612
Total Net Original Cost Rate Base			NOP	4,828,900	2,177,836	94,279	288,203	1,003,456	508,917
Working Capital									
Fuel Inventory									
Wholly-Owned Coal			W10A	62,590	22,232	793	3,106	13,710	9,082
Other Non-Nuclear			W10B	26,124	9,279	331	1,296	5,722	3,791
Nuclear Fuel			W10C	0	0	0	0	0	0
Total Fuel			W10T	88,714	31,511	1,124	4,403	19,432	12,873
Other			W0T1	99,563	42,415	1,920	5,575	21,576	11,370
Total Working Capital			W00	188,277	73,926	3,044	9,978	41,008	24,243
Total Rate Base			RBX	5,017,177	2,251,761	97,324	298,181	1,044,463	533,160

PPLICA Adjusted 12 CP Cost-of-Service Study
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Summary

	LP-5	LPEP	ISA	GH	SL/AL	Standby
Rate Base						
Plant-in-Service						
Production	723,992	21,930	62,510	120,778	9,429	1,980
Transmission	52,914	1,241	3,537	8,827	689	145
Distribution	57,781	1,840	5,081	52,466	137,080	151
Other	27,305	829	2,359	5,629	3,263	75
Common Plant (Acct. 186)	0	0	0	0	0	0
Total Plant-in-Service	861,993	25,840	73,486	187,701	150,462	2,351
Depreciation Reserve						
Production	201,385	6,100	17,388	33,596	2,623	551
Transmission	16,811	394	1,124	2,804	219	46
Distribution	18,847	597	1,655	17,201	55,147	49
General Plant	8,810	267	761	1,816	1,053	24
Intangible Plant	755	23	65	156	90	2
Total Depreciation Reserve	246,609	7,382	20,992	55,573	59,132	672
Amortization Reserve	0	0	0	0	0	0
Total Depreciation & Amort. Reserve	246,609	7,382	20,992	55,573	59,132	672
Total Net Plant in Service	615,384	18,458	52,494	132,128	91,330	1,678
Total Subtractive Adjustment	114,341	3,445	9,834	21,230	8,418	312
Total Additive Adjustment	1,785	54	154	298	23	5
Total Net Original Cost Rate Base	502,827	15,066	42,814	111,195	82,936	1,371
Working Capital						
Fuel Inventory						
Wholly-Owned Coal	11,003	286	1,038	1,104	214	22
Other Non-Nuclear	4,592	119	433	461	89	9
Nuclear Fuel	0	0	0	0	0	0
Total Fuel	15,595	405	1,471	1,565	303	32
Other	11,773	359	1,001	2,362	1,180	33
Total Working Capital	27,368	764	2,472	3,927	1,483	64
Total Rate Base	530,195	15,831	45,286	115,122	84,418	1,436

PPLICA Adjusted 12 CP Cost-of-Service Study
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Summary

	Input	Allocation	Output	Total Pennsylvania Jurisdiction	RS	RTS	GS-1	GS-3	LP-4
Operating Revenues At Present Rates									
Sale of Electricity									
Rate Revenue	RR			2,263,602	909,213	20,360	165,977	520,355	281,626
Energy/Fuel Cost Revenue	ECR			(21,487)	(7,008)	(248)	(1,005)	(4,491)	(3,377)
State Tax Adj Surcharge	STAS			0	0	0	0	0	0
Spec Base Rate Credit Adj	SBRCA			(38,084)	(15,093)	(338)	(2,755)	(8,692)	(4,896)
Interruptible Revenue									
Revenue Credits				23,273	0	0	0	0	2,652
Interruptible Expense				(23,273)	(8,934)	(426)	(1,174)	(5,349)	(3,031)
Net Interruptible Credits				0	(8,934)	(426)	(1,174)	(5,349)	(379)
Economic/Industrial Development									
Revenue Credits				30,624	0	0	0	3,279	13,319
EDI/IDI Expenses				(30,624)	(13,744)	(594)	(1,820)	(6,375)	(3,254)
Net EDI/IDI				(0)	(13,744)	(594)	(1,820)	(3,096)	10,065
Total Sale of Electricity			RRT	2,204,031	864,434	18,754	159,223	498,726	283,039
Annualization	ANN			25,615	8,192	367	3,393	5,340	4,745
Late Payment Charges			R11	7,074	3,508	27	1,314	1,528	377
Total Adj'd Sale of Electricity			RRTT	2,236,720	876,134	19,149	163,930	505,595	288,160
Other Operating Revenues			ROOT	165,535	63,272	2,357	8,694	35,469	22,223
Total Operating Revenues			ROT	2,402,255	939,406	21,506	172,623	541,064	310,384

PPLICA Adjusted 12 CP Cost-of-Service Study
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Summary

	LP-5	LPEP	ISA	GH	SL/AL	Standby
Operating Revenues At Present Rates						
Sale of Electricity						
Rate Revenue	268,654	8,665	21,238	44,746	21,591	1,177
Energy/Fuel Cost Revenue	(4,364)	(116)	(422)	(375)	(72)	(9)
State Tax Adj Surcharge	0	0	0	0	0	0
Spec Base Rate Credit Adj	(4,878)	(144)	(367)	(743)	(358)	(20)
Interruptible Revenue						
Revenue Credits	16,996	0	3,626	0	0	0
Interruptible Expense	(3,356)	(102)	(290)	(560)	(44)	(9)
Net Interruptible Credits	13,640	(102)	3,336	(560)	(44)	(9)
Economic/Industrial Development						
Revenue Credits	13,154	0	872	0	0	0
EDI/IDI Expenses	(3,236)	(97)	(276)	(703)	(515)	(9)
Net EDI/IDI	9,918	(97)	596	(703)	(515)	(9)
Total Sale of Electricity	283,170	8,207	24,381	42,366	20,602	1,130
Annualization	4,973	0	0	(1,014)	(381)	0
Late Payment Charges	133	0	0	135	52	0
Total Adj'd Sale of Electricity	288,276	8,207	24,381	41,486	20,273	1,130
Other Operating Revenues	25,997	692	2,423	3,099	1,253	55
Total Operating Revenues	314,272	8,899	26,804	44,585	21,527	1,185

PPL/ICA Adjusted 12 CP Cost-of-Service Study
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Summary

	Input	Allocation	Output	Total Pennsylvania Jurisdiction	RS	RTS	GS-1	GS-3	LP-4
Operating Expenses									
Operating & Maintenance Exp.									
Production									
Fuel			EOPF1	431,704	153,338	5,471	21,424	94,561	62,645
Power Purchases			EOPP1	252,511	90,992	3,455	12,569	55,801	35,966
Other Production			EOP01	297,079	110,334	4,706	14,881	66,887	40,610
Total Production			EE10T	981,294	354,664	13,632	48,873	217,250	139,221
Transmission			EE20	10,487	4,026	192	529	2,410	1,366
Distribution			EE30	92,936	51,716	2,092	7,738	15,501	5,467
Other Operating & Maint. Expenses			EOMT1	288,210	157,205	4,504	19,185	46,023	24,843
Total Operating & Maintenance Exp.			EE00T	1,372,927	567,610	20,420	76,326	281,185	170,897
Depreciation Expense									
Production			ED10	231,599	88,904	4,234	11,684	53,234	30,159
Transmission			ED20	7,753	2,988	142	393	1,789	1,013
Distribution			ED30	70,147	41,443	1,513	5,654	10,579	3,279
Other Depreciation Exp.			ED88	11,298	5,602	204	714	2,084	1,084
Total Depreciation Expenses			ED0ST	320,797	138,936	6,093	18,444	67,686	35,536
Amortization Expenses (Acct. 406)			ED97T	0	0	0	0	0	0
Total Depreciation & Amortization			ED00	320,797	138,936	6,093	18,444	67,686	35,536
Miscellaneous Allowable Expenses			TX89	(29,674)	(11,378)	(540)	(1,497)	(6,816)	(3,871)
Taxes									
- Other Capital Stock			ET1	30,553	13,600	593	1,801	6,407	3,285
- Other w/o Cap Stock			ET001	57,585	26,403	1,071	3,464	11,592	6,048
Deferred Income Taxes			TXT	(15,424)	(3,234)	(219)	(418)	(4,396)	(3,032)
Net Investment Tax Credit			TX91	(8,625)	(3,876)	(167)	(513)	(1,788)	(911)
Gross Receipts Tax			TXG	98,416	38,550	843	7,213	22,246	12,679
PA & Federal Income Taxes			TSF1	209,078	52,671	(3,567)	25,885	64,140	36,290
Total Taxes			TEX1	371,583	124,114	(1,447)	37,431	98,201	54,358
Total Operating Expenses			TEXP1	2,035,633	819,283	24,526	130,705	440,255	256,920
Return			PRERTN	366,622	120,123	(3,020)	41,919	100,808	53,464
Total Rate Base			RBX	5,017,177	2,251,761	97,324	298,181	1,044,463	533,160
Rate of Return			PRRTR	7.31%	5.33%	-3.10%	14.06%	9.65%	10.03%
Class Rate in % of Total			PRCLRT		73.0	-42.5	192.4	132.1	137.2

PPLICA Adjusted 12 CP Cost-of-Service Study
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Summary

	LP-5	LPEP	ISA	GH	SL/AL	Standby
Operating Expenses						
Operating & Maintenance Exp.						
Production						
Fuel	75,889	1,973	7,159	7,616	1,475	154
Power Purchases	42,954	1,145	4,000	4,746	793	92
Other Production	46,918	1,324	4,233	6,317	757	112
Total Production	165,761	4,441	15,391	18,678	3,024	357
Transmission	1,512	46	131	252	20	4
Distribution	2,367	83	216	2,145	5,604	6
Other Operating & Maint. Expenses	26,673	775	2,347	4,748	1,840	68
Total Operating & Maintenance Exp.	196,313	5,345	18,085	25,824	10,488	435
Depreciation Expense						
Production	33,392	1,011	2,883	5,571	435	91
Transmission	1,122	26	75	187	15	3
Distribution	1,415	47	126	1,409	4,680	4
Other Depreciation Exp.	1,115	34	96	230	133	3
Total Depreciation Expenses	37,044	1,118	3,180	7,397	5,262	101
Amortization Expenses (Acct. 406)	0	0	0	0	0	0
Total Depreciation & Amortization	37,044	1,118	3,180	7,397	5,262	101
Miscellaneous Allowable Expenses	(4,293)	(130)	(371)	(711)	(56	(12)
Taxes						
- Other Capital Stock	3,287	99	280	706	488	9
- Other w/o Cap Stock	6,166	183	533	1,257	853	16
Deferred Income Taxes	(3,877)	(116)	(344)	(394)	616	(10)
Net Investment Tax Credit	(907)	(27)	(77)	(198)	(158)	(2)
Gross Receipts Tax	12,684	361	1,073	1,825	892	50
PA & Federal Income Taxes	28,266	857	1,869	2,990	(574)	250
Total Taxes	45,619	1,357	3,334	6,186	2,116	313
Total Operating Expenses	274,683	7,690	24,228	38,696	17,810	837
Return	39,590	1,209	2,575	5,889	3,717	348
Total Rate Base	530,195	15,831	45,286	115,122	84,418	1,436
Rate of Return	7.47%	7.64%	5.69%	5.12%	4.40%	24.26%
Class Rate in % of Total	102.2	104.5	77.8	70.0	60.3	332.0

PENNSYLVANIA POWER & LIGHT
Allocation of Proposed Rate Increase
50% Reduction in Existing Subsidies under PPLICA's 12 Coincident Peak COSS

	Total Sales Revenue	Rate Base	Current Income	Current ROR %
Residential				
RS, RTD, RTS	906,886,000	2,349,085,000	117,103,000	4.99%
General Service				
GS-1	162,217,000	298,181,000	41,919,000	14.06%
GS-3	507,172,000	1,044,463,000	100,808,000	9.65%
LP-4	273,353,000	533,160,000	53,464,000	10.03%
LP-5	259,612,000	530,195,000	39,590,000	7.47%
LPEP	8,405,000	15,831,000	1,209,000	7.64%
ISA	20,449,000	45,286,000	2,575,000	5.69%
GH	43,628,000	115,122,000	5,889,000	5.12%
Street & Area Lighting	21,161,000	84,418,000	3,717,000	4.40%
Standby	1,148,000	1,436,000	348,000	24.23%
Rate Schedule	2,204,031,000	5,017,177,000	366,622,000	7.31%
Other Revenues	53,479,000			
Annualization Adjustment	25,615,000			
Total Retail Revenues	2,283,125,000	5,017,177,000	366,622,000	

PENNSYLVANIA POWER & LIGHT
Allocation of Proposed Rate Increase
50% Reduction in Existing Subsidies under PPLICA's 12 Coincident Peak COSS

	Current Equalized Rate of Return					Equalized Rate of Return @ $262 Million Increase					
	Percent Increase	Revenue Increase	Income Increase	ROR %	Sales Revenue	Percent Increase	Revenue Increase	Annualization & Other RevenueCredit	Income Increase	ROR %	Sales Revenue
Residential											
RS, RTD, RTS	10.96%	99,356,467	54,552,543	7.307%	1,006,242,467	24.31%	220,487,115	(1,369,000)	121,812,053	10.17%	1,127,373,115
General Service											
GS-1	-22.60%	(36,662,578)	(20,129,911)	7.307%	125,554,422	-13.34%	(21,646,091)	(533,000)	(11,592,328)	10.17%	140,570,909
GS-3	-8.79%	(44,595,543)	(24,485,575)	7.307%	462,576,457	1.79%	9,090,920	(780,000)	5,419,716	10.17%	516,262,920
LP-4	-9.66%	(26,416,488)	(14,504,205)	7.307%	246,936,512	0.29%	803,641	(583,000)	761,347	10.17%	274,156,641
LP-5	-0.59%	(1,542,399)	(846,868)	7.307%	258,069,601	9.83%	25,525,111	(581,000)	14,333,790	10.17%	285,137,111
LPEP	-1.13%	(95,027)	(52,176)	7.307%	8,309,973	8.69%	730,525	0	401,101	10.17%	9,135,525
ISA	6.54%	1,337,198	734,200	7.307%	21,786,198	18.09%	3,698,764	0	2,030,839	10.17%	24,147,764
GH	10.53%	4,595,777	2,523,352	7.307%	48,223,777	24.52%	10,699,138	100,000	5,819,550	10.17%	54,327,138
Street & Area Lighting	21.10%	4,465,291	2,451,707	7.307%	25,626,291	42.08%	8,904,505	37,000	4,868,782	10.17%	30,065,505
Standby	-38.56%	(442,697)	(243,067)	7.307%	705,303	-32.04%	(367,813)	0	(201,951)	10.17%	780,187
Rate Schedule		0	0	7.307%	2,204,031,000	11.70%	257,925,815	(3,709,000)	143,652,898	10.17%	2,461,956,815
Other Revenues		0	0		53,479,000		795,000		436,502		54,274,000
Annualization Adjustment		0	0		25,615,000		2,914,000		1,599,957		28,529,000
Total Retail Revenues		0	0		2,283,125,000		261,634,815		145,689,357	10.21%	2,544,759,815

PENNSYLVANIA POWER & LIGHT
Allocation of Proposed Rate Increase
50% Reduction in Existing Subsidies under PPLICA's 12 Coincident Peak COSS

	Current Sales Revenue	Revenue at Current Equal ROR	Current Subsidy	Revenue at Proposed Equal ROR	Proposed Subsidy	Proposed Sales Revenue	Proposed * Revenue Increase	Proposed * Percentage Increase
Residential					50%			
RS, RTD, RTS	906,886,000	1,006,242,467	(99,356,467)	1,127,373,115	(49,678,233)	1,077,694,882	170,808,882	18.83%
General Service								
GS-1	162,217,000	125,554,422	36,662,578	140,570,909	18,331,289	158,902,198	(3,314,802)	-2.04%
GS-3	507,172,000	462,576,457	44,595,543	516,262,920	22,297,771	538,560,691	31,388,691	6.19%
LP-4	273,353,000	246,936,512	26,416,488	274,156,641	13,208,244	287,364,885	14,011,885	5.13%
LP-5	259,612,000	258,069,601	1,542,399	285,137,111	771,200	285,908,311	26,296,311	10.13%
LPEP	8,405,000	8,309,973	95,027	9,135,525	47,514	9,183,038	778,038	9.26%
ISA	20,449,000	21,786,198	(1,337,198)	24,147,764	(668,599)	23,479,165	3,030,165	14.82%
GH	43,628,000	48,223,777	(4,595,777)	54,327,138	(2,297,888)	52,029,249	8,401,249	19.26%
Street & Area Lighting	21,161,000	25,626,291	(4,465,291)	30,065,505	(2,232,645)	27,832,860	6,671,860	31.53%
Standby	1,148,000	705,303	442,697	780,187	221,348	1,001,536	(146,464)	-12.76%
Rate Schedule	2,204,031,000	2,204,031,000	(0)	2,461,956,815	(0)	2,461,956,815	257,925,815	11.70%
Other Revenues	53,479,000					54,274,000	795,000	
Annualization Adjustment	25,615,000					28,529,000	2,914,000	
Total Retail Revenues	2,283,125,000					2,544,759,815	261,634,815	10.28%

* These increases are based on the Company's requested $262 million increase. If the Commission authorizes a lower increase, as recommended by PPLICA, these values should be adjusted to reflect the approved increase.

PENNSYLVANIA POWER & LIGHT COMPANY
SUMMARY OF CLASS REVENUE INCREASES
USING COST-OF-SERVICE CRITERIA RECOMMENDED BY PPLICA*

RATE SCHEDULE	PRESENT REVENUE (w/roll-ins)	PROPOSED REVENUE (w/o cap)	PROPOSED % INCREASE (w/o cap)	PROPOSED $ INCREASE (w/o cap)	INCREASE IN EXCESS OF 1.5 X SYSTEM (17.6%)	"CAPPED" $ INCREASE	"CAPPED" % INCREASE
RS	$886,748,156	$1,053,722,834	18.83%	$166,974,678	$11,350,376	$155,624,301	17.55%
RTS	$19,773,844	$23,497,259	18.83%	$3,723,415	$253,105	$3,470,310	17.55%
RTD	$363,891	$432,412	18.83%	$68,521	$4,658	$63,863	17.55%
GS-1	$161,735,899	$158,436,487	-2.04%	($3,299,412)	$0	$0	0.00%
GS-3	$506,985,301	$538,367,691	6.19%	$31,382,390	$0	$37,587,935	7.41%
LP-4:							
LP-4, L4C	$267,879,730	$279,582,944	4.37%	$11,703,214	$0	$15,016,205	5.61%
INTERRUPTIBLE	$18,728,254	$22,055,332	17.77%	$3,327,078	$40,269	$3,286,809	17.55%
ECO/IND DEV CR.	($13,254,820)	($14,273,227)	7.68%	($1,018,407)	$0	($1,018,407)	7.68%
LP-5:							
LP-5	$148,535,286	$157,538,352	6.06%	$9,003,066	$0	$10,822,489	7.29%
LP-6	$32,506,451	$33,729,757	3.76%	$1,223,306	$0	$1,626,705	5.00%
INTERRUPTIBLE	$91,661,728	$107,934,006	17.75%	$16,272,278	$185,644	$16,086,633	17.55%
ECO/IND DEV CR.	($13,090,615)	($13,292,954)	1.55%	($202,339)	$0	($202,339)	1.55%
LPEP	$8,404,855	$9,183,145	9.26%	$778,290	$0	$879,361	10.46%
ISA	$20,448,546	$23,479,021	14.82%	$3,030,475	$0	$3,268,424	15.98%
IS-1	$186,035	$197,551	6.19%	$11,516	$0	$13,793	7.41%
BL	$480,920	$471,109	-2.04%	($9,811)	$0	$0	0.00%
SA	$4,292,175	$5,645,498	31.53%	$1,353,323	$600,046	$753,277	17.55%
SM	$1,618,482	$2,128,789	31.53%	$510,307	$226,264	$284,044	17.55%
SHS	$14,778,848	$19,438,619	31.53%	$4,659,771	$2,066,083	$2,593,688	17.55%
SE	$346,823	$456,176	31.53%	$109,353	$48,486	$60,867	17.55%
TS(R)	$54,756	$72,021	31.53%	$17,265	$7,655	$9,610	17.55%
SI-1(R)	$69,788	$91,792	31.53%	$22,004	$9,756	$12,248	17.55%
GH-1(R)	$36,095,375	$43,047,344	19.26%	$6,951,969	$617,231	$6,334,738	17.55%
GH-2(R)	$7,533,184	$8,984,075	19.26%	$1,450,891	$128,817	$1,322,074	17.55%
STANDBY	$1,148,211	$1,001,699	-12.76%	($146,512)	$0	$0	0.00%
TOTAL PUC	$2,204,031,103	$2,461,927,731	11.70%	$257,896,628	$15,538,391	$257,896,628	11.70%
OTHER REV	$53,479,000	$54,274,118	1.49%	$795,118		$795,118	1.49%
ANN ADJ.	$25,615,499	$28,529,260	11.37%	$2,913,761		$2,913,761	11.37%
FERC	$483,916,000	$483,916,000	0.00%	$0		$0	0.00%
TOTAL OP REV	$2,767,041,602	$3,028,647,109	9.45%	$261,605,507		$261,605,507	9.45%

* Based on PP&L requested $262 million increase. If the Commission authorizes a lower increase, these values should be adjusted to reflect the approved increase.

Exhibit ___ (SJB-4)

PENNSYLVANIA POWER & LIGHT COMPANY
SUMMARY OF PROPOSED CLASS REVENUE INCREASES
ASSUMING A $20 MILLION AUTHORIZED REVENUE INCREASE

RATE SCHEDULE	PRESENT REVENUE (w/roll-ins)	PROPOSED REVENUE (w/o cap)	PROPOSED % INCREASE (w/o cap)	PROPOSED $ INCREASE (w/o cap)	INCREASE IN EXCESS OF 1.5 X SYSTEM (17.6%)	REVISED % INCREASE (@ $262 Million)	REVISED $ INCREASE (@ $262 Million)	REVISED $ INCREASE (@ $20 Million)	REVISED % INCREASE (@ $20 Million)
RS	$886,748,156	$1,053,722,834	18.83%	$166,974,678	$11,350,376	17.55%	$155,624,301	$12,138,646	1.37%
RTS	$19,773,844	$23,497,259	18.83%	$3,723,415	$253,105	17.55%	$3,470,310	$270,683	1.37%
RTD	$363,891	$432,412	18.83%	$68,521	$4,658	17.55%	$63,863	$4,981	1.37%
GS-1	$161,735,899	$158,436,487	-2.04%	($3,299,412)	$0	0.00%	$0	$0	0.00%
GS-3	$506,985,301	$538,367,691	6.19%	$31,382,390	$0	7.41%	$37,587,935	$2,931,847	0.58%
LP-4:									
LP-4, L4C	$267,879,730	$279,582,944	4.37%	$11,703,214	$0	5.61%	$15,016,205	$1,171,259	0.44%
INTERRUPTIBLE	$18,728,254	$22,055,332	17.77%	$3,327,078	$40,269	17.55%	$3,286,809	$256,370	1.37%
ECO/IND DEV CR.	($13,254,820)	($14,273,227)	7.68%	($1,018,407)	$0	7.68%	($1,018,407)	($1,018,407)	7.68%
LP-5:									
LP-5	$148,535,286	$157,538,352	6.06%	$9,003,066	$0	7.29%	$10,822,489	$844,151	0.57%
LP-6	$32,506,451	$33,729,757	3.76%	$1,223,306	$0	5.00%	$1,626,705	$126,882	0.39%
INTERRUPTIBLE	$91,661,728	$107,934,006	17.75%	$16,272,278	$165,644	17.55%	$16,086,633	$1,254,752	1.37%
ECO/IND DEV CR.	($13,090,615)	($13,292,954)	1.55%	($202,339)	$0	1.55%	($202,339)	($202,339)	1.55%
LPEP	$8,404,855	$9,183,145	9.26%	$778,290	$0	10.46%	$879,361	$68,590	0.82%
ISA	$20,448,546	$23,479,021	14.82%	$3,030,475	$0	15.98%	$3,268,424	$254,936	1.25%
IS-1	$186,035	$197,551	6.19%	$11,516	$0	7.41%	$13,793	$1,076	0.58%
BL	$480,920	$471,109	-2.04%	($9,811)	$0	0.00%	$0	$0	0.00%
SA	$4,292,175	$5,645,498	31.53%	$1,353,323	$600,046	17.55%	$753,277	$58,755	1.37%
SM	$1,618,482	$2,128,789	31.53%	$510,307	$226,264	17.55%	$284,044	$22,155	1.37%
SHS	$14,778,848	$19,438,619	31.53%	$4,659,771	$2,066,083	17.55%	$2,593,688	$202,307	1.37%
SE	$346,823	$456,176	31.53%	$109,353	$48,486	17.55%	$60,867	$4,748	1.37%
TS(R)	$54,756	$72,021	31.53%	$17,265	$7,655	17.55%	$9,610	$750	1.37%
SI-1(R)	$69,788	$91,792	31.53%	$22,004	$9,756	17.55%	$12,248	$955	1.37%
GN-1(R)	$36,095,375	$43,047,344	19.26%	$6,951,969	$617,231	17.55%	$6,334,738	$494,108	1.37%
GN-2(R)	$7,533,184	$8,984,075	19.26%	$1,450,891	$128,817	17.55%	$1,322,074	$103,121	1.37%
STANDBY	$1,148,211	$1,001,699	-12.76%	($146,512)	$0	0.00%	$0	$0	0.00%
TOTAL PUC	$2,204,031,103	$2,461,927,731	11.70%	$257,896,628	$15,538,391	11.70%	$257,896,628	$18,990,326	0.86%
OTHER REV	$53,479,000	$54,274,118	1.49%	$795,118		1.49%	$795,118	$795,118	1.49%
ANN ADJ.	$25,615,499	$28,529,260	11.37%	$2,913,761		11.37%	$2,913,761	$214,556	0.84%
FERC	$483,916,000	$483,916,000	0.00%	$0		0.00%	$0	$0	0.00%
TOTAL OP REV	$2,767,041,602	$3,028,647,109	9.45%	$261,605,507		9.45%	$261,605,507	$20,000,000	0.72%

Exhibit ___ (SJB-5)

PENNSYLVANIA POWER & LIGHT COMPANY
PPLICA PROPOSED LP-5, LP-6, AND INTERRUPTIBLE RATES
REVENUE SUMMARY - ASSUMING A $262 MILLION INCREASE

PRESENT REVENUES

	Present Base	Roll-in Special Base Rate Adj. (-0.64%)	Roll-in St Tax Adj. Surcharge (-.49%)	Roll-in ECR $0.010836	Special Base Rate Adj. (-1.66%)	ECR ($0.000781)	Total Present Revenues
LP-5	$124,536,516	($797,034)	($596,194)	$28,118,816	($2,510,951)	($2,026,651)	$146,724,502
LP-5 : LP-6	$27,031,041	($172,999)	($129,406)	$6,392,037	($549,803)	($460,703)	$32,110,167
Interruptible	$69,478,880	($444,665)	($332,616)	$25,219,457	($1,559,090)	($1,817,681)	$90,544,286
Total (based on bill freq.)	$221,046,438	($1,414,697)	($1,058,216)	$59,730,311	($4,619,844)	($4,305,036)	$269,378,956
Actual Revenue	$223,703,000	($1,431,699)	($1,070,933)	$60,543,712	($4,676,952)	($4,363,662)	$272,703,466
Economic Devp credit	($12,333,000)		$60,432		($1,003)		($12,273,571)
Industrial Devp credit	($821,000)		$4,023		($67)		($817,044)
Total	$210,549,000	($1,431,699)	($1,006,479)	$60,543,712	($4,678,022)	($4,363,662)	$259,612,850

PROPOSED REVENUES

	Proposed Base	Special Base Rate Adj. (-1.66%)	ECR ($0.000781)	Total Proposed Revenues	Increase	% Increase
LP-5	$162,186,634	($2,692,298)	($2,026,651)	$157,467,684	$10,743,182	7.3%
LP-5 : LP-6	$34,763,890	($577,081)	($460,703)	$33,726,106	$1,615,938	5.0%
Interruptible	$110,117,234	($1,827,946)	($1,817,681)	$106,471,606	$15,927,321	17.6%
Total (based on bill freq.)	$307,067,757	($5,097,325)	($4,305,036)	$297,665,396	$28,286,441	10.5%
Actual Revenue	$310,768,208	($5,158,752)	($4,363,662)	$301,245,793	$28,542,328	10.5%
Economic Devp credit	($12,471,954)			($12,471,954)		
Industrial Devp credit	($821,000)			($821,000)		
Total	$297,475,254	($5,158,752)	($4,363,662)	$287,952,839	$28,339,989	10.9%

PENNSYLVANIA POWER & LIGHT COMPANY
PPLICA PROPOSED LP-5, LP-6, AND INTERRUPTIBLE RATES
PROOF OF REVENUE ANALYSIS - ASSUMING A $262 MILLION INCREASE

LP-5

Present Rate	UNITS	RATE	REVENUE
All Kw	4,953,919	$4.3900	$21,747,704
Kwh Blocks			
First 150/kw (max 1,200,000)	618,259,296	$0.0486	$30,047,402
Next 100/kw	489,809,450	$0.0443	$21,698,559
Next 150/kw	703,161,490	$0.0368	$25,876,343
Excess	783,714,030	$0.0321	$25,157,220
Subtotal	2,594,944,266		$102,779,524
TOD Metering	774	$12.0000	$9,288
Total			$124,536,516
Proposed			
All Kw	4,953,919	$5.8950	$29,203,486
Kwh Blocks			
First 400/kw	1,929,777,036	$0.0550	$106,176,817
Excess	665,167,230	$0.0403	$26,794,721
Subtotal	2,594,944,266		$132,971,538
TOD Metering	774	$15.0000	$11,610
Total			$162,186,634

LP-5 - Interruptible

Present Rate	UNITS	RATE	REVENUE
All Kw	485,656	$9.6000	$4,662,298
Kwh Blocks			
First 400/kw	194,262,400	$0.0321	$6,235,823
Excess	289,036,600	$0.0214	$6,185,383
Subtotal	483,299,000		$12,421,206
TOD Metering	168	$12.0000	$2,016
Total			$17,085,520
Proposed			
All Kw	485,656	$11.2883	$5,482,230
Kwh Blocks			
First 400/kw	194,262,400	$0.0541	$10,504,381
Excess	289,036,600	$0.0360	$10,419,414
Subtotal	483,299,000		$20,923,796
TOD Metering	168	$15.0000	$2,520
Total			$26,408,546

PENNSYLVANIA POWER & LIGHT COMPANY
PPLICA PROPOSED LP-5, LP-6, AND INTERRUPTIBLE RATES
PROOF OF REVENUE ANALYSIS – ASSUMING A $262 MILLION INCREASE

LP-5 : LP-6 Present Rate	UNITS	RATE	REVENUE
All Kw	1,057,999	$4.3900	$4,644,616
Kwh Blocks			
First 150/kw (max 1,200,000)	85,682,700	$0.0486	$4,164,179
Next 100/kw	105,799,900	$0.0443	$4,686,936
Next 150/kw	158,699,850	$0.0368	$5,840,154
Excess	239,706,550	$0.0321	$7,694,580
Subtotal	589,889,000		$22,385,850
TOD Metering	48	$12.0000	$576
Total			$27,031,041
Proposed			
All Kw (10,000 kw min)	1,067,331	$5.9592	$6,360,489
Kwh Blocks			
First 400/kw (min use)	426,932,400	$0.0546	$23,321,792
Next 200/kw	136,526,200	$0.0318	$4,339,164
Excess	28,709,000	$0.0258	$741,364
Subtotal	592,167,600		$28,402,321
TOD Metering	72	$15.0000	$1,080
Total			$34,763,890

LP-5: LP-6 – Interruptible Present Rate	UNITS	RATE	REVENUE
All Kw	931,427	$9.6000	$8,941,699
Kwh Blocks			
First 400/kw	372,570,800	$0.0321	$11,959,523
Excess	1,471,507,230	$0.0214	$31,490,255
Subtotal	1,844,078,030		$43,449,777
TOD Metering	157	$12.0000	$1,884
Total			$52,393,361
Proposed			
All Kw	931,427	$11.2883	$10,514,226
Kwh Blocks			
First 400/kw	372,570,800	$0.0541	$20,146,080
Excess	1,471,507,230	$0.0360	$53,046,028
Subtotal	1,844,078,030		$73,192,108
TOD Metering	157	$15.0000	$2,355
Total			$83,708,688

Determination of Interruptible Credits
PPLICA Adjusted 12 CP Cost-of-Service @ Proposed Rates
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Revenue Requirements

	Input	Allocation	Output	Total Pennsylvania Jurisdiction	RS	RTS	GS-1	GS-3	LP-4
Revenue Requirements Excluding									
Return Income & Gross Receipts Tax									
O&M Production			EE10	981,294	354,664	13,632	48,873	217,250	139,221
Demand Component			EE10D	213,244	81,858	3,899	10,758	49,015	27,769
Energy Component			EE10E	768,050	272,806	9,733	38,116	168,235	111,452
O&M Transmission			EE20	10,487	4,026	192	529	2,410	1,366
O&M Distribution			EE30	92,936	51,716	2,092	7,738	15,501	5,467
Demand Component			EE30D	49,588	23,345	1,374	3,116	12,852	4,992
Customer Component			EE30C	43,348	28,370	718	4,623	2,649	475
O&M Customer Accounts			EE56	51,982	43,958	552	4,669	2,000	443
O&M Customer Services & Info			EE60	18,067	15,693	214	1,766	279	12
O&M Sales			EE65	4,959	2,003	102	264	1,171	607
O&M Admin & General			EE79	149,437	72,417	2,515	9,329	27,525	15,040
Demand Component			EE79D	83,962	33,764	1,709	4,456	19,782	10,324
Energy Component			EE79E	32,126	11,411	407	1,594	7,037	4,662
Customer Component			EE79C	33,349	27,241	399	3,279	706	54
O&M Adjustments			EE99	63,765	23,134	1,120	3,117	15,048	8,741
Demand Component			EE99D	57,732	22,060	1,044	2,898	13,238	7,558
Energy Component			EE99E	8,136	2,890	103	404	1,782	1,181
Customer Component			EE99C	(2,103)	(1,816)	(27	(185)	28	2
Depreciation & Amortization			ED00	320,797	138,936	6,093	18,444	67,686	35,536
Demand Component			ED00D	284,093	112,789	5,630	14,870	66,427	35,382
Customer Component			ED00C	36,704	26,147	463	3,574	1,259	154
Taxes Other than Income & GR			TOTI	65,921	33,709	1,312	4,442	12,199	5,586
Demand Component			TOTID	47,823	20,264	1,090	2,686	11,595	5,476
Energy Component			TOTIE	388	138	5	19	85	56
Customer Component			TOTIC	17,710	13,307	217	1,737	518	54
Misc Allowable Expense			TX89	(29,674)	(11,378)	(540	(1,497)	(6,816)	(3,871)
Other Operating Revenues - CR			ROOT	165,535	63,272	2,357	8,694	35,469	22,223
Demand Component			ROOTD	31,806	12,961	667	1,712	7,548	3,843
Energy Component			ROOTE	126,522	44,940	1,603	6,279	27,714	18,360
Customer Component			ROOTC	7,207	5,372	87	703	208	21
Revenue Requirements Excluding									
Return Income & Gross Receipts Tax			TXDT	1,564,436	665,605	24,928	89,021	318,784	185,924
Demand Component			TXDTD	690,408	275,771	13,834	36,367	162,128	85,759
Energy Component			TXDTE	682,178	242,305	8,645	33,854	149,426	98,991
Customer Component			TXDTC	191,850	147,530	2,449	18,800	7,230	1,173

Determination of Interruptible Credits
PPLICA Adjusted 12 CP Cost-of-Service @ Proposed Rates
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Revenue Requirements

	LP-5	LPEP	ISA	GH	SL/AL	Standby	LP-5 Prod. Only
Revenue Requirements Excluding Return Income & Gross Receipts Tax							
O&M Production	165,761	4,441	15,391	18,678	3,024	357	30,746
Demand Component	30,746	931	2,655	5,129	400	84	30,746
Energy Component	135,016	3,510	12,736	13,549	2,624	273	0
O&M Transmission	1,512	46	131	252	20	4	0
O&M Distribution	2,367	83	216	2,145	5,604	6	0
Demand Component	2,025	61	175	1,501	141	6	0
Customer Component	342	22	42	644	5,464	0	0
O&M Customer Accounts	141	1	0	177	21	0	0
O&M Customer Services & Info	2	0	0	66	15	0	0
O&M Sales	604	18	51	126	10	2	0
O&M Admin & General	16,059	463	1,432	2,861	1,756	40	8,747
Demand Component	10,382	314	896	2,131	175	28	8,747
Energy Component	5,647	147	533	567	110	11	0
Customer Component	30	2	3	163	1,471	0	0
O&M Adjustments	9,867	293	863	1,519	38	26	8,531
Demand Component	8,438	256	729	1,381	107	23	8,531
Energy Component	1,430	37	135	144	28	3	0
Customer Component	(2)	(0)	(0)	(6)	(97)	(0)	0
Depreciation & Amortization	37,044	1,118	3,180	7,397	5,262	101	34,395
Demand Component	36,934	1,111	3,167	7,105	578	101	34,395
Customer Component	110	7	13	292	4,685	0	0
Taxes Other than Income & GR	4,866	144	409	1,414	1,828	13	3,234
Demand Component	4,761	140	398	1,288	112	13	3,234
Energy Component	68	2	6	7	1	0	0
Customer Component	37	2	5	119	1,714	0	0
Misc Allowable Expense	(4,293)	(130)	(371)	(711)	(56)	(12)	0
Other Operating Revenues - CR	25,997	692	2,423	3,099	1,253	55	3,199
Demand Component	3,741	113	323	819	68	10	3,199
Energy Component	22,241	578	2,098	2,232	432	45	0
Customer Component	14	1	2	47	753	0	0
Revenue Requirements Excluding Return Income & Gross Receipts Tax	207,933	5,785	18,880	30,825	16,268	482	82,453
Demand Component	87,367	2,634	7,507	17,384	1,418	239	82,453
Energy Component	119,920	3,117	11,312	12,034	2,330	243	0
Customer Component	646	33	61	1,407	12,519	0	0

Determination of Interruptible Credits
PPLICA Adjusted 12 CP Cost-of-Service @ Proposed Rates
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Revenue Requirements

	Input	Allocation	Output	Total Pennsylvania Jurisdiction	RS	RTS	GS-1	GS-3	LP-4
At Class % Rate of Return	RTRA			10.17%	8.68%	-1.14%	15.31%	11.48%	12.95%
Return on Rate Base			RTNA1	510,275	195,397	(1,114)	45,638	119,878	69,040
Demand Component			RTNAD	440,530	149,537	(1,006)	34,824	115,577	67,336
Energy Component			RTNAE	7,832	2,272	(11)	561	1,855	1,394
Customer Component			RTNAC	61,912	43,587	(98)	10,253	2,445	310
Adjustment to Taxable Income			TAT	(82,018)	(48,907)	(1,926)	(6,528)	(13,259)	(3,901)
Demand Component			TATD	(69,824)	(31,246)	(1,786)	(4,160)	(17,430)	(7,277)
Energy Component			TATE	24,493	8,764	323	1,217	5,389	3,521
Customer Component			TATC	(36,687)	(26,425)	(462)	(3,585)	(1,218)	(145)
Federal Income Tax Adjustment			TAFI	804	358	16	47	169	86
Demand Component			TAFID	701	282	14	37	165	86
Energy Component			TAFIE	0	0	0	0	0	0
Customer Component			TAFIC	103	76	1	10	3	0
State Income Tax Adjustment			TSTA	213	96	5	13	45	23
Demand Component			TSTAD	186	76	5	10	44	23
Energy Component			TSTAE	0	0	0	0	0	0
Customer Component			TSTAC	27	20	0	3	1	0
Summary for Federal Income Tax Calc.									
Taxable Income			TFTI1	429,274	146,943	(3,019)	39,171	106,832	65,248
Demand Component			TFTI1D	371,593	118,650	(2,772)	30,711	98,356	60,168
Energy Component			TFTI1E	32,325	11,036	312	1,778	7,244	4,915
Customer Component			TFTI1C	25,355	17,258	(559)	6,681	1,232	165
Federal Income Tax									
(ie. .35/.65*taxable income+tax adj)			TFIT1	231,951	79,481	(1,610)	21,139	57,694	35,220
Demand Component			TFIT1D	200,790	64,171	(1,478)	16,574	53,126	32,484
Energy Component			TFIT1E	17,406	5,942	168	958	3,901	2,646
Customer Component			TFIT1C	13,756	9,368	(300)	3,608	667	89
Adj. to State Taxable Income			TASI	83	100	1	12	(12)	(9)
Demand Component			TASID	(215)	(76)	(3)	(10)	(47)	(31)
Energy Component			TASIE	146	52	2	7	32	21
Customer Component			TASIC	152	124	2	15	3	0
Summary for State Income Tax Calc.									
Taxable Income			TSTI1	660,504	226,167	(4,644)	60,275	164,346	100,373
Demand Component			TSTID	571,467	182,462	(4,268)	47,237	151,270	92,536
Energy Component			TSTIE	49,877	17,030	482	2,743	11,177	7,582
Customer Component			TSTIC	39,160	26,675	(858)	10,294	1,898	255
State Income Tax									
(ie. .1099/.8901*taxable income+tax adj)			TSIT1	81,765	28,021	(568)	7,455	20,337	12,416
Demand Component			TSIT1D	70,745	22,604	(522)	5,842	18,721	11,448
Energy Component			TSIT1E	6,158	2,103	60	339	1,380	936
Customer Component			TSIT1C	4,862	3,314	(106)	1,274	235	31

Exhibit ___ (SJB-7)
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Determination of Interruptible Credits
PPLICA Adjusted 12 CP Cost-of-Service @ Proposed Rates
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Revenue Requirements

	LP-5	LPEP	ISA	GH	SL/AL	Standby	LP-5 Prod. Only
At Class % Rate of Return	11.69%	9.23%	5.70%	8.43%	6.34%	24.55%	10.17%
Return on Rate Base	61,982	1,462	2,583	9,704	5,353	352	45,285
Demand Component	60,250	1,420	2,500	9,173	571	346	45,285
Energy Component	1,528	31	70	109	16	6	0
Customer Component	204	10	12	422	4,765	0	0
Adjustment to Taxable Income	(1,038)	(40)	(29)	(1,840)	(4,543)	(5)	(1,748)
Demand Component	(5,168)	(145)	(413)	(2,002)	(183)	(14)	(1,748)
Energy Component	4,235	111	397	446	80	9	0
Customer Component	(106)	(7)	(13)	(285)	(4,441)	(0)	0
Federal Income Tax Adjustment	87	3	7	19	13	0	76
Demand Component	86	3	7	18	1	0	76
Energy Component	0	0	0	0	0	0	0
Customer Component	0	0	0	1	11	0	0
State Income Tax Adjustment	21	1	1	5	3	0	19
Demand Component	21	1	1	5	0	0	19
Energy Component	0	0	0	0	0	0	0
Customer Component	0	0	0	0	3	0	0
Summary for Federal Income Tax Calc.							
Taxable Income	61,052	1,425	2,562	7,887	825	347	43,633
Demand Component	55,190	1,279	2,095	7,194	390	332	43,633
Energy Component	5,763	143	467	555	96	15	0
Customer Component	99	4	(1)	137	339	0	0
Federal Income Tax							
(ie. .35/.65*taxable income+tax adj)	32,961	770	1,387	4,265	457	187	23,570
Demand Component	29,804	691	1,136	3,892	212	179	23,570
Energy Component	3,103	77	252	299	52	8	0
Customer Component	53	2	(0)	75	194	0	0
Adj. to State Taxable Income	(13)	(0)	(1)	(1)	7	(0)	(45)
Demand Component	(39)	(1)	(3)	(5)	(0)	(0)	(45)
Energy Component	26	1	2	3	0	0	0
Customer Component	0	0	0	1	7	0	0
Summary for State Income Tax Calc.							
Taxable Income	93,913	2,192	3,941	12,132	1,277	534	67,082
Demand Component	84,869	1,966	3,220	11,064	600	511	67,082
Energy Component	8,892	220	722	856	149	23	0
Customer Component	152	6	(1)	212	528	0	0
State Income Tax							
(ie. .1099/.8901*taxable income+tax adj)	11,616	272	468	1,503	161	66	8,302
Demand Component	10,500	244	399	1,371	74	63	8,302
Energy Component	1,098	27	89	106	18	3	0
Customer Component	19	1	(0)	26	68	0	0

Determination of Interruptible Credits
PPLICA Adjusted 12 CP Cost-of-Service @ Proposed Rates
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Revenue Requirements

	Input	Allocation	Output	Total Pennsylvania Jurisdiction	RS	RTS	GS-1	GS-3	LP-4
Income Taxes			TSF1	313,716	107,502	(2,178)	28,594	78,030	47,636
Demand Component			TSF1D	271,534	86,775	(2,000)	22,416	71,848	43,933
Energy Component			TSF1E	23,564	8,045	228	1,296	5,281	3,583
Customer Component			TSF1C	18,618	12,682	(406)	4,882	902	121
Annualization Revenues	ANN			28,529	9,122	409	3,779	5,948	5,285
Demand Component			ANN1D	16,189	3,380	273	2,920	3,854	3,965
Energy Component			ANN1E	8,921	3,165	112	448	1,965	1,300
Customer Component			ANN1C	3,419	2,577	24	411	129	20
Late Payment Charges			R11	7,869	3,903	30	1,461	1,700	419
Demand Component			R111D	4,466	2,319	(8)	1,224	1,122	55
Energy Component			R111E	2,460	873	31	124	542	358
Customer Component			R111C	943	711	7	113	36	6
Revenue Reqmnts Before GRT			RRBA	2,352,029	955,478	21,197	158,013	509,044	296,897
Demand Component			RRBAD	1,381,817	506,384	10,563	89,463	344,577	193,008
Energy Component			RRBAE	702,194	248,584	8,719	35,139	154,055	102,309
Customer Component			RRBAC	268,018	200,511	1,915	33,411	10,413	1,579
Gross Receipts Tax @ 44 Mill			GRTA1	109,928	44,575	996	7,514	23,781	13,927
Demand Component			GRTA1D	64,549	23,569	498	4,308	16,088	9,068
Energy Component			GRTA1E	32,842	11,627	408	1,644	7,206	4,785
Customer Component			GRTA1C	12,536	9,380	90	1,562	487	74
Total Revenue Requirements			RRA1	2,461,957	1,000,054	22,193	165,527	532,825	310,824
Demand Component			RRA1D	1,446,366	529,953	11,061	93,771	360,665	202,077
Energy Component			RRA1E	735,036	260,211	9,127	36,783	161,260	107,094
Customer Component			RRA1C	280,555	209,891	2,005	34,973	10,900	1,653

Determination of Interruptible Credits
PPLICA Adjusted 12 CP Cost-of-Service @ Proposed Rates
Pennsylvania Power & Light
Cost Allocation Details - Future Test Year Ended 9/30/95
Revenue Requirements

	LP-5	LPEP	ISA	GH	SL/AL	Standby	LP-5 Prod. Only
Income Taxes	44,577	1,042	1,875	5,768	618	253	31,872
Demand Component	40,304	935	1,534	5,263	286	242	31,872
Energy Component	4,201	104	341	405	70	11	0
Customer Component	72	3	(0)	101	262	0	0
Annualization Revenues	5,539	0	0	(1,129)	(424)	0	0
Demand Component	3,968	(42)	(147)	(1,310)	(668)	(4)	0
Energy Component	1,553	41	146	157	30	4	0
Customer Component	18	1	1	24	214	0	0
Late Payment Charges	148	0	0	150	58	0	0
Demand Component	(284)	(12)	(42)	101	(9)	0	0
Energy Component	428	12	41	43	8	0	0
Customer Component	4	0	1	6	59	0	0
Revenue Reqmnts Before GRT	308,805	8,288	23,338	47,276	22,605	1,088	159,611
Demand Component	184,237	5,043	11,730	33,029	2,952	831	159,611
Energy Component	123,669	3,200	11,537	12,347	2,379	256	0
Customer Component	900	46	71	1,900	17,273	1	0
Gross Receipts Tax @ 44 Mill	14,475	381	1,074	2,131	1,024	50	7,346
Demand Component	8,649	230	531	1,465	105	38	7,346
Energy Component	5,783	150	540	577	111	12	0
Customer Component	42	2	3	89	808	0	0
Total Revenue Requirements	323,280	8,670	24,412	49,407	23,628	1,138	166,957
Demand Component	192,886	5,273	12,261	34,494	3,057	869	166,957
Energy Component	129,452	3,349	12,076	12,925	2,490	268	0
Customer Component	942	48	74	1,988	18,081	1	0

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing testimonies on all known parties of record to this proceeding, by Federal Express delivery, Harrisburg parties being hand delivered, properly addressed as follows:

OFFICE OF ADMINISTRATIVE LAW JUDGES
Hon. Robert A. Christianson
Administrative Law Judge
PA Public Utility Commission
G-08A North Office Building
P. O. Box 3265
Harrisburg, PA 17105-3265

PENNSYLVANIA POWER & LIGHT COMPANY
Paul E. Russell, Esquire
Associate General Counsel
Pennsylvania Power & Light Co.
Two North Ninth Street
Allentown, PA 18101-1179

Thomas P. Gadsden, Esquire
Anthony C. DeCusatis, Esquire
David B. MacGregor, Esquire
Morgan, Lewis & Bockius
2000 One Logan Square
Philadelphia, PA 19103

Christopher J. Barr, Esquire
Morgan, Lewis & Bockius
1800 M Street, N.W.
Washington, D.C. 20026-5869

OFFICE OF TRIAL STAFF
Johnnie E. Simms, Esquire
Kenneth L. Mickens, Esquire
Stephen E. Gorka, Esquire
Office of Trial Staff
PA Public Utility Commission
P. O. Box 3265
Harrisburg, PA 17105-3265

OFFICE OF CONSUMER ADVOCATE
Mary C. Kenney, Esquire
Tanya J. McCloskey, Esquire
Assistant Consumer Advocates
Office of Consumer Advocate
1425 Strawberry Square
Harrisburg, PA 17120

Mr. Thomas Catlin
Mr. Matthew I. Kahal
Exeter Associates, Inc.
12510 Prosperity Drive,
Suite 350
Silver Spring, MD 20904

Mr. Dale Bridenbaugh
MHB Technical Associates
1723 Hamilton Avenue-Suite K
San Jose, CA 95125

OFFICE OF SMALL BUSINESS ADVOCATE
Karen Oill Moury, Esquire
Office of Small Business Advocate
Suite 1102, Commerce Building
300 North Second Street
Harrisburg, PA 17101

Mr. Robert D. Knecht
Industrial Economics Incorporated
2067 Massachusetts Avenue
Cambridge, MA 02140

BETHLEHEM STEEL CORPORATION
Joan O. Brandeis, Esquire
Schnader, Harrison, Segal & Lewis
1600 Market Street Suite 3600
Philadelphia, PA 19103

Mr. Maurice Brubaker
Drazen-Brubaker & Associates, Inc.
7730 Forsyth Boulevard, Suite 200
St. Louis, MO 63105-1819

DEPARTMENT OF DEFENSE
David A. McCormick, General Attorney
Regulatory Law Office
Office of The Judge Advocate General
Department of the Army,
DAJA-RL 3848
901 N. Stuart Street, Room 713
Arlington, VA 22203-1837

UNIVERSITY/COLLEGE COALITION
Daniel P. Delaney, Esquire
James P. Melia, Esquire
Kirkpatrick & Lockhart
204 North Third Street
Harrisburg, PA 17101-1507

UNIVERSITY/COLLEGE COALITION
Cook, Eisdorfer & Associates
2258 Schuetz Road
Suite 205
St. Louis, MO 63146

THE LANCASTER CHAMBER OF COMMERCE AND INDUSTRY
Christopher S. Underhill, Esq.
Hartman Underhill & Brubaker
221 East Chestnut Street
Lancaster, PA 17602

CENTRAL EASTERN PENNSYLVANIA FUEL OIL DEALERS
Robert P. Haynes, Esquire
Mette, Evans & Woodside
3401 North Front Street
P. O. Box 5950
Harrisburg, PA 17110-0950

Mr. Steven Andersen
Economic & Policy Analysis, Inc.
13300 Council Bluff Drive
Austin, TX 78727

MID-ATLANTIC ENERGY PROJECT (SIERRA CLUB)
Alan J. Barak, Esquire
Mid-Atlantic Energy Project
Weidner Energy Law Clinic
3700 Vartan Way
Harrisburg, PA 17110-9450

CROWN AMERICAN REALTY TRUST
Kenneth Zielonis, Esquire
Stevens & Lee
208 North Third Street - Suite 310
P. O. Box 12090
Harrisburg, PA 17108-2090

David M. Kleppinger /dt
David M. Kleppinger, Esquire

Dated this 12th day of April, 1995, in Harrisburg, Pennsylvania.

SCHNADER, HARRISON, SEGAL & LEWIS
ATTORNEYS AT LAW
SUITE 3600
1600 MARKET STREET
PHILADELPHIA, PENNSYLVANIA 19103-4252
215-751-2000
FAX 215-751-2205

ORIGINAL

KJK

DIRECT DIAL NUMBER

(215) 751-2278

DOCUMENT FOLDER

April 12, 1995

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PUBLIC UTILITY COMMISSION
SECRETARY BUREAU

Mr. John G. Alford, Secretary
Pennsylvania Public Utility Commission
Room B-20, North Office Building
P.O. Box 3265
Harrisburg, PA 17105-3265

**Re: Pennsylvania Public Utility Commission, et al. v. Pennsylvania Power & Light Company
Docket No. R-00943271**

Dear Secretary Alford:

Enclosed please find an original and two copies of the Direct Testimony and exhibits of Maurice Brubaker on behalf of Bethlehem Steel Corporation in the above-captioned proceeding. As evidenced by the attached Certificate of Service, all parties of record have been served.

I am enclosing a self-addressed, stamped envelope and would request that you date-stamp the copy of the transmittal letter and return it to me for my files.

Very truly yours,

Joan O. Brandeis

Joan O. Brandeis
For SCHNADER, HARRISON, SEGAL & LEWIS
Attorneys for Bethlehem Steel Corporation

Enclosures
cc: The Honorable Robert A. Christianson
All Parties of Record

Before the

Pennsylvania Public Utility Commission

Docket No. R-00943271

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PUBLIC UTILITY COMMISSION
SECRETARY BUREAU

PENNSYLVANIA POWER & LIGHT COMPANY

Testimony and Exhibit

of

MAURICE BRUBAKER

DOCKETED
APR 20 1995

On Behalf of

Bethlehem Steel Corporation

DOCUMENT
FOLDER

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

Direct Testimony 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 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.

EDI & IDI

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.

Exhibit MEB-3 (   )
Schedule 1

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

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

Exhibit MEB-3 ( )
Schedule 1
Page 3 of 4

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	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	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												

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, et al.	:	
	:	DOCKET NO: R-00943271
v.	:	
PENNSYLVANIA POWER & LIGHT COMPANY	:	

RECEIVED
APR 12 1995
PUBLIC UTILITY COMMISSION
SECRETARY BUREAU

CERTIFICATE OF SERVICE

I hereby certify that I am serving the foregoing document by UPS Next Day Air or Federal Express upon the persons listed below:

Paul E. Russell, Esquire
Pennsylvania Power & Light
2 North 9th Street
Allentown, PA 19101-1179
Phone: 610-774-4254
Fax: 610-774-6726

Thomas P. Gadsden, Esquire
Anthony C. DeCusatis, Esquire
David B. MacGregor, Esquire
Morgan, Lewis & Bockius
2000 One Logan Square
Philadelphia, PA 19103
Phone: 215-963-5234
Fax: 215-963-5299

Johnnie Simms, Esquire
Kenneth Mickens, Esquire
PA PUC - Office of Trial Staff
Pitnick Building - 3rd Floor
901 North 7th Street
Harrisburg, PA 17102
Phone: 717-787-1976

Tanya J. McCloskey
Mary C. Kenney, Asst. Consumer Advocate
Office of the Consumer Advocates
1425 Strawberry Square
Harrisburg, PA 17120
Phone: 717-783-5048
Fax: 717-783-7152

Karen Oill Moury, Esquire
Office of Small Business Advocate
Suite 1102 Commerce Building
300 North Second Street
Harrisburg, PA 17101
Phone: 717-783-1515
Fax: 717-783-2831

David M. Kleppinger, Esquire
McNees, Wallace and Nurick
100 Pine Street, Box 1166
Harrisburg, PA 17108-1166
Phone: 717-237-5214
Fax: 717-236-2665

F:\PUBL\MEJ\JOB\BETH\R943271.SRV
04/10/95 5:18pm

James R. Brokenshire
599 Eisenhower Boulevard
Harrisburg, PA 17111-2397

Kenneth Zielonis, Esquire
Stevens & Lee
208 North 3rd Street, Suite 310
Harrisburg, PA 17108-2040

Robert D. Knecht
Industrial Economics Incoporated
2067 Massachusetts Avenue
Cambridge, Massachusetts 02140

Christopher J. Barr, Esquire
Morgan, Lewis & Bockius
1800 M Street, N.W.
Washington, DC 20026-5869

David A. McCormick, Esquire
Department of the Army
Office of the Judge Advocate General
901 North Stuart Street
Arlington, Virginia 22203-1837

D. Jane Drennan, Esquire
Sarah E. Tomalty, Esquire
Drennan & Associates
1216 16th Street, N.W.
Washington, PA 20036

Thomas S. Catlin
Exeter Associates, Inc.
12510 Prosperity Drive
Suite 350
Silver Spring, Maryland 20904

Stephen J. Baron, President
J. Kennedy and Associates, Inc.
Suite 475
35 Glenlake Parkway
Atlanta, Georgia 30328

Alan J. Barak, Esquire
Mid-Atlantic Energy Project
Widener University Energy Law Clinic
3700 Vartan Way
Harrisburg, Pennsylvania 17110
Phone: 717-541-1967
Fax: 717-541-1970

David L. Pennington
Catherine Panchou Cox
Harvey, Pennington, Herting
& Renneisen, Ltd.
Eleven Penn Center
1835 Market Street, 29th Floor
Philadelphia, PA 19103
215-563-4470

Eugene M. Brady
Executive Director
Commission on Economic Opportunity
211 South Main Street
Wilkes-Barre, PA 18701-1596

Daniel P. Delaney
James P. Melia
Kirkpatrick & Lockhart
204 North Third Street
Harrisburg, PA 17101-1507

Wayne M. Thomas
Kohn, Nast & Graf, P.C.
1101 Market Street, 24th Floor
Philadelphia, PA 19107
215-238-1700

Mr. Maurice Brubaker
Drazen-Brubaker & Associates, Inc.
7730 Forsyth Boulevard, Suite 200
St. Louis, MO 63105-0840

Robert P. Haynes, III, Esquire
3401 North Front Street
P.O. Box 5950
Harrisburg, PA 17110-0950
Phone: 717-232-5000

Dale Bridenbaugh
MHB Technical Associates
1723 Hamilton Avenue
Suite K
San Jose, CA 95125

Kenneth Eisdorfer
Cook, Eisdorfer & Associates
2258 Schuetz Road
Suite 205
St. Louis, MO 63146

Steven Anderson
Economic & Policy Analysis, Inc.
13300 Council Bluff Drive
Austin, TX 78727

Joan O. Brandeis

Joan O. Brandeis

Dated this 11th day of
April, 1995

F:\PUBL\MEJ\JOB\BETH\R943271.SRV
04/10/95 5:18pm

COMMONWEALTH OF PENNSYLVANIA

OFFICE OF SMALL BUSINESS ADVOCATE
Suite 1102, Commerce Building
300 North Second Street
Harrisburg, Pennsylvania 17101

Bernard A. Ryan, Jr.
Small Business Advocate

(717) 783-2525
(717) 783-2831 (FAX)

April 12, 1995

John G. Alford, Secretary
Pennsylvania Public Utility Commission
Room B-18, North Office Building
Harrisburg, PA 17105

RECEIVED
95 APR 12 PM 12: 05
PA. P.U.C.
INFO. CONTROL DIV.

Re: Pennsylvania Public Utility Commission v. Pennsylvania Power & Light Company Docket No. R-943271

Dear Secretary Alford:

Enclosed is a certificate of service pursuant to 52 Pa. Code §5.412(f) evidencing the service of the direct testimony and exhibit of Robert D. Knecht for filing in the above docket.

Sincerely,

Karen Oill Moury

Karen Oill Moury
Assistant Small Business Advocate

Enclosure

DOCUMENT FOLDER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-943271
PENNSYLVANIA POWER & LIGHT COMPANY	:	

CERTIFICATE OF SERVICE

I certify that I am today serving copies of the direct testimony and exhibit of Robert D. Knecht on behalf of the Office of Small Business Advocate in the manner indicated upon the persons addressed below:

Paul E. Russell, Esquire
Associate General Counsel
Pennsylvania Power & Light Company
Two North Ninth Street
Allentown, PA 18101-1179
(overnight mail 4/11)

Thomas P. Gadsden, Esquire
Anthony C. DeCusatis, Esquire
David B. MacGregor, Esquire
Morgan, Lewis & Bockius
2000 One Logan Square
Philadelphia, PA 19103
(overnight mail 4/11)

Christopher J. Barr, Esquire
Morgan, Lewis & Bockius
1800 M Street N.W.
Washington, D.C. 20026-5869
(overnight mail 4/11)

Johnnie E. Simms, Esquire
Kenneth L. Mickens, Esquire
Stephen E. Gorka, Esquire
Office of Trial Staff
Pa. Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105
(hand delivered 4/12)

Alan J. Barak, Esquire
Mid-Atlantic Energy Project
Widener Energy Law Clinic
3700 Vartan Way
Harrisburg, PA 17110-9450
(hand delivered 4/12)

Tanya McCloskey, Esquire
Mary C. Kenney, Esquire
Gicine P. Brignola, Esquire
Office of Consumer Advocate
1425 Strawberry Square
Harrisburg, PA 17120
(hand delivered 4/12)

Dr. Charles Johnson
Exeter Associates, Inc.
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904
(overnight mail 4/11)

David M. Kleppinger, Esquire
McNees, Wallace & Nurick
100 Pine Street
P.O. Box 1166
Harrisburg, PA 17108-1166
(hand delivered 4/12)

Joan O. Brandeis, Esquire
Schnader, Harrison, Segal and Lewis
1600 Market Street, Suite 3600
Philadelphia, PA 19103-4252
(overnight mail 4/11)

Mr. Maurice Brubaker
Drazen-Brubaker & Assoc, Inc.
7730 Forsyth Blvd., Suite 200
P. O. Box 16140
St. Louis, Missouri 63105-1819
(overnight mail 4/11)

DOCUMENT
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APR 17 1995

Wayne M. Thomas, Esquire
1101 Market Street, 24th Floor
Philadelphia, PA 19107
(overnight mail 4/11)

James P. Melia, Esquire
Daniel P. Delaney, Esquire
Kirkpatrick & Lockhart
240 North Third Street
Harrisburg, PA 17101-1503
(hand delivered 4/12)

Mr. Kenneth Eisdorfer
Cook, Eisdorfer & Associates
Suite 205
2258 Schuetz Road
St. Louis, MO 63146
(overnight mail 4/11)

D. Jane Drennan, Esquire
Drennan & Associates
1216 16th Street, N.W.
Washington, D.C. 20036
(overnight mail 4/11)

Kenneth Zielonis, Esquire
Stevens & Lee
Suite 310, 208 N. Third Street
P. O. Box 12090
Harrisburg, PA 17108
(hand delivered 4/12)

Stephen J. Selden, Esquire
Bethléhem Steel Corporation
Eighth and Eaton Avenues
Bethlehem, PA 18016
(overnight mail 4/11)

David A. McCormick, Esquire
Regulatory Law Office (U-3848)
Department of the Army
901 North Stuart St. Room 400
Arlington, VA 22203-1837
(overnight mail 4/11)

Mr. Craig Kuennen
Comm. on Economic Opportunity
211 S. Main Street
Wilkes Barre, PA 18701-1596
(overnight mail 4/11)

Robert P. Haynes, III, Esquire
Mette, Evans & Woodside
3401 North Front Street
P. O. Box 5950
Harrisburg, PA 17110-0950
(hand delivered 4/12)

Karen Oill Moury

Karen Oill Moury
Assistant Small Business Advocate

Date: April 12, 1995

K.7/...

to main file

R-943271

Harrisburg Center for Peace&Justice
315 Peffer St., Harrisburg, PA 17102 (717) 233-3072

April 12, 1995

DOCUMENT FOLDER

RECEIVED
95 APR 19 AM 11:18
PA. P.U.C.
INFO. CONTROL DIV.

Michael C. Schnierle, ALJ
PA Public Utility Commission
P.O. box 3265
Harrisburg, PA 17105-3265

RE: PA Power & Light Co. Rate Increase

Dear Michael Schnierle:

I arrived at the Museum auditorium Thursday, March 30, 1995 around 3:10 PM and was told I would not be able to present my testimony on the PP&L rate increase request because the hearing officer had called a recess.

The Harrisburg Center for Peace & Justice opposes the PP&L requested $261 million rate hike.

The Center for Peace & Justice was organized in 1965 and since its inception has pursued the goal of alleviating social injustices. Currently the Center staff strives to educate the community about housing issues and opportunities. Center staff regularly counsel low-income individuals who are experiencing serious housing problems. These individuals are homeowners and renters who often times cannot pay their rent/mortgage, utilities and have enough money left for food, transportation, medical expenses and other necessities.

I am familiar with the PP&L CARES program and often refer low-income elderly and disabled persons to the program. The CARES program is not sufficient! Many individuals and families remain in substandard housing or homeless due to their inability to pay already high electric bills. Subsidized housing programs and private landlords are not admitting individuals and families who have outstanding utility balances on their credit reports. Many of these consumers have or are living in dwelling units where there is electric heat and monthly bills run $100 + for someone receiving a monthly SSI check of $550.

I would appreciate the opportunity to personally discuss these problems. Please contact me at 717-233-3072.

DOCKETED
APR 24 1995

Sincerely,

Kay Pickering
Housing Counselor

cc: Consumer Advocate

KJR

Commonwealth of Pennsylvania

Pennsylvania Public Utility Commission
PO Box 3265, Harrisburg, PA 17105-3265

April 13, 1995

In Re: R-00943271,
R-00943271C0001-C0138

(See letter dated 3/8//95)

Pennsylvania Public Utility Commission
v.
Pennsylvania Power and Light Company

Investigation into a proposed $261,000,000 rate increase.

N O T I C E

The following information was provided to parties to the above-captioned proceeding by hearing notice dated March 8, 1995:

This is to inform you that an Initial Hearing on the above-captioned case will be held on Tuesday, March 21, 1995 at 10:00 a.m. in an available hearing room, Ground Floor, North Office Building, North Street and Commonwealth Avenue, Harrisburg, Pennsylvania.

Additionally, a further hearing schedule has been set as follows:

Thursday, March 23, 1995	at	10:00 a.m.
Friday, March 24, 1995	at	10:00 a.m.
Monday, March 27, 1995	at	10:00 a.m.
Tuesday, March 28, 1995	at	10:00 a.m.
Wednesday, March 29, 1995	at	10:00 a.m.
Tuesday, April 25, 1995	at	10:00 a.m.
Wednesday, April 26, 1995	at	10:00 a.m.
Thursday, April 27, 1995	at	10:00 a.m.
Friday, April 28, 1995	at	10:00 a.m.
Tuesday, May 2, 1995	at	10:00 a.m.
Wednesday, May 3, 1995	at	10:00 a.m.
Monday, May 22, 1995	at	10:00 a.m.
Tuesday, May 23, 1995	at	10:00 a.m.
Wednesday, May 24, 1995	at	10:00 a.m.
Thursday, May 25, 1995	at	10:00 a.m.
Friday, May 26, 1995	at	10:00 a.m.

DOCUMENT
FOLDER

All of the above-scheduled hearings will also be held in an available hearing room, North Office Building, North Street and Commonwealth Avenue, Harrisburg, Pennsylvania 17105-3265.

The presiding officer in this proceeding is Acting Chief Administrative Law Judge Robert A. Christianson. Acting Chief Judge Christianson can be contacted at PO Box 3265, Harrisburg, Pennsylvania 17105-3265; telephone (717) 787-1191.

pc: Acting Chief Judge Christianson
Kevin Cadden - Rm. 111
John Frazier - BPL
Office of Trial Staff (4)
Law Bureau - Rm. G28
Consumer Advocate (2)
Small Business Advocate
Bill Barrett
Norma Lewis
Janice Zurat, Scheduling Officer
Calendar File
Beth Plantz
Docket Section

ORIGINAL

MCNEES, WALLACE & NURICK
ATTORNEYS AT LAW

100 PINE STREET
P. O. BOX 1166
HARRISBURG, PA 17108-1166
TELEPHONE (717) 232-8000
FAX (717) 237-5300

OF COUNSEL
ROBERT H. GRISWOLD
SAMUEL A. SCHRECKENGAUST, JR.

BRUCE D. BAGLEY
TERRY R. BOSSERT
ALAN R. BOYNTON, JR.
ERIC L. BROSSMAN
ROBERT M. CHERRY
WILLIAM A. CHESNUTT
DAVID B. DISNEY
MICHAEL A. DOCTROW
ELIZABETH A. DOUGHERTY
HARVEY FREEDENBERG
JAMES L. FRITZ
FRANCIS B. HAAS, JR.
W. JEFFRY JAMOUNEAU
MICHAEL G. JARMAN
DAVID M. KLEPPINGER
BERNARD A. LABUSKES, JR.
DELANO M. LANTZ
RICHARD R. LEFEVER
DAVID E. LEHMAN
CLYDE W. McINTYRE
FRANKLIN A. MILES, JR.
ROBERT A. MILLS
STEPHEN A. MOORE
HERBERT R. NURICK
JOHN S. OYLER
TIMOTHY J. PFISTER
GARY A. RITTER
EDWARD W. ROTHMAN
DANA STEVENS SCADUTO
ROBERT D. STETS
RICHARD W. STEVENSON
DIANE M. TOKARSKY
DAVID M. WATTS, JR.
STEVEN J. WEINGARTEN
NEAL S. WEST
NORMAN I. WHITE
LAWRENCE R. WIEDER
GARY F. YENKOWSKI
WILLIAM M. YOUNG, JR.
SCOTT A. GOULD
P. NICHOLAS GUARNESCHELLI
ROBERT G. HAAS
BRIAN F. JACKSON
DONALD B. KAUFMAN
MICHAEL R. KELLEY
PETER F. KRIETE
JAMES W. KUTZ
CAMILLE C. MARION
PATRICK J. MURPHY
SHARON R. PAXTON
CHUONG H. PHAM
JONATHAN H. RUDD
BRUCE R. SPICER
CAROL A. STEINOUR
CATHERINE E. WALTERS
DERRICK P. WILLIAMSON
ERIC N. ATHEY
DAVID M. BAKER
JONATHAN C. BERRY
BRETT D. DAVIS
JAMES P. DeANGELO
JAMES P. DOUGHERTY
KATHLEEN A. DUNST
ROBERT J. GODUTO

April 14, 1995

John G. Alford, Secretary
PA Public Utility Commission
B-20 North Office Building
P. O. Box 3265
Harrisburg, PA 17120

VIA HAND DELIVERY

Re: Pennsylvania Public Utility Commission, et al. v. Pennsylvania Power & Light Company, Docket No. R-00943271

Dear Secretary Alford:

Enclosed for filing in the above-captioned proceeding, please find an original and two (2) copies of the Direct Testimony and Exhibits of Lane Kollen on behalf of PP&L Industrial Customer Alliance.

As evidenced by the attached Certificate of Service, all parties of record have been duly served.

Please date stamp a copy of this transmittal letter and kindly return for our filing purposes.

Very truly yours,

McNEES WALLACE & NURICK

By David M. Kleppinger
David M. Kleppinger

DOCUMENT FOLDER

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95 APR 14 AM 10:30
PA. P.U.C.
SEC. CONTROL DIV.

DMK/dt
Enclosures
cc: Certificate of Service

40