PPL ICA Stmt 7-SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

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INFO. CONTROL DIV.

DOCKETED
MAY 31 1995

SURREBUTTAL TESTIMONY

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

MAY 1995

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BEFORE THE

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PENNSYLVANIA POWER & LIGHT COMPANY

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SURREBUTTAL TESTIMONY OF STEPHEN J. BARON

Q. Please state your name and business address.

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

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes. I have previously submitted both direct testimony and rebuttal testimony.

Q. What is the purpose of your surrebuttal testimony?

A. I will be responding to the rebuttal testimony submitted by PP&L witnesses Joseph M. Kleha and Oliver G. Kasper.

Q. Would you please respond to issues raised in Mr. Kleha's testimony?

A. Mr. Kleha addresses two adjustments that I have made to the Company's 12 coincident peak ("CP") cost-of-service study. As I discussed in my direct testimony, I relied upon the Company's 12 CP cost-of-service study in this proceeding, although I made three specific adjustments to the Company's analysis to more accurately reflect cost-of-service. These three adjustments are 1) a change in the treatment of interruptible load, 2) an allocation of EDI/IDI costs to all customer classes, and 3) a correction of the mismatch incorporated in the Company's study associated with NUG payments. Of these three adjustments, Mr. Kleha has agreed to the appropriateness of the adjustment that I made to the allocation of NUG costs. Although he did not incorporate the exact methodology which I developed, as he indicates in his rebuttal testimony, the effect is the same as that recommended in my direct testimony.

Q. Does Mr. Kleha agree with your proposed adjustment to the PP&L 12 CP cost-of-service study to more accurately reflect the impact of interruptible load on rate schedules LP-4, LP-5 and ISA?

A. No. Mr. Kleha continues to argue that the Company's $300 per kW rate base offset is the appropriate means to reflect the value of interruptible load in the PP&L cost-of-service study. As I indicated in my direct testimony, I do not accept the Company's "value of interruptible load" methodology. I believe that a cost-of-service method, which assigns 50% of production demand-related costs to interruptible load, is a more reasonable portrayal of the cost of serving interruptible customers. However, for the purposes of developing a cost-of-service study in this proceeding, I did utilize the Company's basic framework. However, instead of using a $300 per kW rate base (investment) offset to reflect interruptible load, I utilized the value of the revenue credits proposed by PP&L in this proceeding for interruptible customers. For the most part, PP&L is offering interruptible credits of $6.00 per kW and, in the case of customers that can be interrupted with 30 minutes notice, $8.00 per kW. These $6.00 and $8.00 per kW credits that the Company is proposing to offer in this case are approximately the same level as the $7.24 PJM Capacity Deficiency Rate (after applying the active load management adjustment of 1.19). These credits are also close to the $8.36 per kW cost-of-service based credit that I have calculated in my direct testimony.

Using this basis to "value" interruptible load in PP&L's cost-of-service study more accurately reflects the costs on the PJM system (the PJM Capacity Deficiency Rate) and does not result in a self-fulfilling revenue requirement deficiency for the rate schedules and classes containing interruptible load. Mr. Kleha does not respond to this built-in revenue requirement deficiency problem, which I raised in my direct testimony.

Essentially, PP&L's cost-of-service approach builds in a revenue requirement deficiency automatically to Rate Schedules LP-4, LP-5 and ISA since the interruptible credit contained in the cost study (based on a $300 investment offset) does not equate to the actual proposed interruptible credits. As a result, the difference is made up by the other members of these rate schedules. This is an inappropriate approach to conducting a cost-of-service study. Finally, although I have not made a specific study of all of the revenue requirements associated with a PP&L installed combustion turbine, it is clear that PP&L did not include any depreciation expense, O&M expense, or an active load management adjustment to its interruptible load value analysis. These additional "interruptible load" revenue requirements and adjustments are appropriate, even if one were to accept the Company's assertions.

Q. **Do you have any additional comments on Mr. Kleha's rebuttal testimony?**

A. Yes. The final issue that I would like to address regarding Mr. Kleha's rebuttal testimony concerns the Company's proposed allocation of EDI/IDI credits. In my direct testimony, I acknowledged that the Company's rationale for offering EDI/IDI credits was that they benefit <u>all customer classes</u>. As such, I allocated the cost of these credits to all rate classes. This systemwide EDI/IDI benefit is reiterated in PP&L witness Kasper's rebuttal testimony, on page 39, when he states:

> **"This benefits all of the Company's customers"** (Kasper rebuttal, page 39, line 18)

Despite PP&L's clear position that these credits benefit all classes, Mr. Kleha objects to this as an allocation concept and continues, in his rebuttal testimony, to support a methodology that assigns these costs directly to the rate class in which customers receiving credits reside. As I pointed out in my direct testimony, this approach makes no sense. The example for Rate Schedule ISA, with one customer, clearly shows the futility of the Company's methodology wherein the economic development credit provided to the single customer on Rate Schedule ISA is then charged back to that same customer through the cost-of-service study.

Finally, even OCA witness Dr. Charles Johnson recognizes the inappropriateness of the Company's methodology with respect to the assignment of EDI/IDI credits directly to customer classes whose customers are receiving the credits. Despite the fact that an allocation of these credit "costs" to all customer classes would impose some additional costs on residential customers, Dr. Johnson has recognized the reasonableness of this approach[1].

Q. Do you have any additional comments regarding PP&L witness Kleha's testimony?

A. No.

[1] Dr. Johnson also proposes that 50% of the costs of these credits be absorbed by PP&L, and he recommends that the remaining costs be allocated to classes on total revenues.

Q. Would you please comment on the rebuttal testimony submitted by PP&L witness Oliver Kasper?

A. There are a number of issues raised in Mr. Kasper's rebuttal testimony that I wish to address. First, Mr. Kasper states that PP&L's position regarding the Company's recommended revenue distribution, should the Company receive an increase less than its overall rate request, is to proportionately scale back its proposed increase distribution. Mr. Kasper, on page 4, at lines 1 through 3 of his rebuttal testimony, continues to support a "1.5 x overall rate increase cap" on each rate class, which is identical to the proposal that I have made. However, <u>Mr. Kasper does not believe that the ratemaking principle of gradualism should apply to interruptible customers</u>.

I believe that it is appropriate to impose a "1.5 x system average increase cap" on all rate schedules, including the optional interruptible rate schedule within rate LP-5. Although Mr. Kasper has not quantified the impact of his proposal on interruptible customers in his testimony, in response to a data request of PPLICA, he indicated that PP&L's large interruptible industrial customers would receive <u>a 22% increase under the Company's proposal, even if PP&L received no overall revenue requirement increase in this case</u>. This is an unreasonable ratemaking approach. My proposal to cap increases at "1.5 x the system average," including interruptible service, should be adopted by the Commission in this proceeding.

Q. Mr. Kasper discusses the fact that the Company's proposed interruptible increases are not large relative to the previous rates interruptible customers paid prior to 1992. Is this relevant in this proceeding?

A. No. I do not dispute the Company's rate calculations, which compare the Company's proposed interruptible rates to the mix of firm and interruptible rates on which PP&L's current interruptible customers took service prior to the 1992 introduction of the Company's LP-5 interruptible rate option. However, this does not address the facts at issue in this case; <u>the Company is proposing a 27% average increase for LP-5 interruptible customers</u>. The fact that such customers may or may not have paid higher rates in 1991 is not germane to the issues in this case: namely, the Company's exceedingly high interruptible rate increases, which would occur even if the Company is granted no overall revenue increase by the Commission. As such, I believe that the Company's reliance on a comparison of past rates paid by PP&L's industrial customers, to proposed rates, should not be considered as valid evidence in evaluating the reasonableness of the Company's proposals in this case.

Q. On page 31, at lines 6 through 8 of his rebuttal testimony, Mr. Kasper asserts that interruptible industrial customers "as a group will receive no increase at all in this proceeding, relative to rate levels established in the Company's last base rate case." Do you agree with this comparison?

A. No. The Company is making a comparison between customers who, for the most part, previously took <u>firm service</u> to customers who are <u>now subject to interruption</u>. Comparing the rates paid by firm customers in 1986 to interruptible rates for these same customers in 1995 is unfair and inappropriate. Even PP&L recognizes some value to interruptible load, yet Mr. Kasper's comparison does not distinguish between firm and interruptible service.

Q. On page 31 of his testimony, at lines 24 through 26, Mr. Kasper states that you are effectively seeking to undo the Commission's recent order closing the optional interruptible power tariff. Is this your intention?

A. No. As Mr. Kasper knows, I did not address this issue in my direct testimony. However, to clarify for Mr. Kasper and the Company, I am not recommending that the Commission's recent order be undone. In particular, I have not objected to the Company's proposed capping of the amount of interruptible load on the PP&L system. The Commission's order, as I understand it, directed the Company and other parties to file information to determine an appropriate interruptible rate in this proceeding. In addition, PP&L has independently proposed to cap the amount of interruptible load at 500 mWs. PPLICA has not raised an objection to this capping in this case. What we are objecting to is the Company's unreasonable proposed 27% increase to interruptible customers in this proceeding. Such customers would receive a 22% increase, even if PP&L receives no additional revenues in this proceeding.

Presumably, PP&L would have to reduce rates to all other customer classes, even if it receives no revenue increase from the Commission, in order to implement its desired interruptible rate changes.

Q. On page 31 at lines 24 and 25, Mr. Kasper states that the PPLICA proposed rate credit "would be $9.90 per kW." Is Mr. Kasper's analysis correct?

A. Not really. Although, Mr. Kasper indicates that he has calculated the implied interruptible credit associated with the PPLICA LP-5/LP-6 interruptible rate, his analysis only reflects the implied credit for a hypothetical LP-6 customer with a mix of firm and interruptible load that is <u>not representative of the entire group</u> of LP-5/LP-6 interruptible customers. As such, his analysis, although arithmetically correct, is <u>highly misleading</u>. The PPLICA-recommended interruptible rate, which I presented in my direct testimony, is based on an increase to the current LP-5 optional interruptible rate (LP-5I) of "1.5 x the system average increase," or 17.6%, assuming that PP&L received its entire rate request. This produces an implied interruptible credit of $7.10 per kW, not the $9.90 per kW calculated by Mr. Kasper.

Mr. Kasper's analysis, in which he develops a $9.90 per kW interruptible credit, is highly misleading because it assumes that only 16% of actual on-peak demand would be subject to a billing demand charge.[2] Under the current PP&L optional interruptible tariff and under the PPLICA proposed tariff that I am recommending, an interruptible customer must take service on this tariff for <u>both firm and interruptible load</u>. Mr. Kasper's example, which assumes that an interruptible customer only has 13,000 kw of interruptible load but only 100 kW of firm load, is simply not realistic and does not reflect the load characteristics of the PP&L interruptible customers. When interruptible customers utilize the PPLICA proposed interruptible rate for their firm service, <u>they would pay a demand charge of $11.29 per kW</u>, compared to the proposed LP-6 firm demand charge that I am recommending of $5.96 per kW.[3] This substantially higher firm demand charge associated with the PPLICA-proposed interruptible rate reduces the effective interruptible credit for the average PP&L industrial interruptible customer that has <u>both firm and interruptible load</u>. Since such customers would be required to take firm service on the proposed interruptible rate, Mr. Kasper's calculation is misleading and not representative of the facts in this case.

Q. On page 35 of Mr. Kasper's testimony, at lines 16 through 26, he indicates that he disagrees with PPLICA's proposal to use "the same rate design as the current

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[2] The actual values for PP&L LP-5 interruptible customers is 36%.

[3] Per the PPLICA-recommended LP-5/LP-6 interruptible rate and LP-6 firm rate, as shown in Baron Direct Testimony, Exhibit ____(SJB-6), page 3 of 3.

interruptible rate" because, in particular, it was originally designed as an economic development initiative. Is this a valid criticism?

A. No. Whether or not one accepts that the initial rationale for PP&L's current optional interruptible rate was to assist economic development, the facts in this proceeding are that the PPLICA-proposed increase, at full rate relief, to the interruptible rate is 2-1/2 times our proposed increase to firm LP-5 customers and 3-1/2 times the increase to firm LP-6 customers. Clearly, PPLICA's proposed continued use of the same basic rate form does not obviate the fact that PPLICA is proposing a substantially greater increase to industrial interruptible customers than it is proposing to corresponding firm industrial customers. As a result, it is irrelevant that the initial basis for the current interruptible rate structure may have been an economic development initiative. The fact is that the PPLICA proposed increase for LP-5 interruptible customers of 17.55% is a substantial increase compared to the PPLICA proposed increases for firm industrial customers of between 5% and 7%, assuming that PP&L received its entire rate increase request. This is clearly not a continuation of the status-quo, as implied by Mr. Kasper's testimony.

Q. Does that complete your surrebuttal testimony?

A. Yes.

OTS Statement No. SR-3
Date: May 19, 1995

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PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PENNSYLVANIA POWER & LIGHT COMPANY

Docket No. R-00943271

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Surrebuttal Testimony

of

Paul M. Yarolin

Office of Trial Staff

DOCKETED
MAY 31 1995

Concerning:

Rate Structure

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Paul M. Yarolin and my business address is the North Office Building, P.O. Box 3265, Harrisburg, Pennsylvania 17105-3265.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I earned an Associate Degree in Mechanical Engineering from The Pennsylvania State University in 1963 and a Bachelor of Science Degree in Commerce and Finance from Wilkes College in 1971.

Q. HOW LONG HAVE YOU BEEN EMPLOYED BY THE PENNSYLVANIA PUBLIC UTILITY COMMISSION?

A. I have been employed by the Commission since 1974.

Q. WHAT IS YOUR JOB TITLE?

A. I am a Fixed Utility Valuation Engineer in the Rate Structure/Engineering Section, Energy Division of the Office of Trial Staff.

Q. MR. YAROLIN, HAVE YOU PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I have submitted OTS Statement No. 3.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the Pennsylvania Power & Light Company's Statement 8-R, which is the Rebuttal Testimony of Oliver G. Kasper, regarding: (a) the minimum monthly charge for residential customers; (b) Residential Service - Thermal Storage (Rate Schedule RTS) and related matters; and, (c) Rate Schedule SE - an energy only street lighting service. I will also respond to comments made by Office of Consumer Advocate witness Dr. Charles E. Johnson in his Statement No. 3A.

Q. WHAT IS THE BASIS FOR MR. KASPER'S DISAGREEMENT WITH THE OTS PROPOSAL TO REDUCE THE MINIMUM MONTHLY CHARGE TO $5.90 FROM THE COMPANY'S PROPOSED $7.20?

A. Although the Company did not specifically address the OTS proposed minimum monthly charge of $5.90, it did state its reasons for rejecting a charge that is less than its proposed $7.20 (PP&L Statement 8-R, page 7).

Q. WHAT ARE MR. KASPER'S REASONS FOR REJECTING A MINIMUM MONTHLY CHARGE THAT IS LESS THAN PP&L'S PROPOSED $7.20?

A. The reasons given by Mr. Kasper at page 1 of Statement 8-R are:

(1) The use of a lower customer charge spreads the recovery of the remaining customer costs over too large an amount of customer energy usage. Also, including these costs in KWH charges sends the wrong price signal and makes revenue recovery less stable.

(2) Its current customer charge (minimum monthly charge) is understated since it has not filed a base rate case in 10 years.

(3) Increasing the customer charge (minimum monthly charge) by $2.40/month would not cause an undue hardship on the vast majority of residential ratepayers and won't cause customers to ration access to the electric system. In addition, the $7.20/month customer charge would not be the highest in the state, but the $4.80/month customer charge would be the lowest among major electric utilities in the state.

Q. WHAT ARE YOUR COMMENTS CONCERNING THE COMPANY'S REJECTION OF A MINIMUM MONTHLY CHARGE THAT IS LESS THAN ITS PROPOSED $7.20?

A. First of all, Mr. Kasper makes the assumption that the Company's proposed increased annual revenue requirement of $261,634,767 is correct and that the $30,711,312 (1,066,365 x $2.40 x 12) proposed revenue increase in the residential minimum monthly charge is a necessary element in determining the Company's increased annual revenue requirement. The OTS disagrees with the Company's proposed revenue requirement increase of $261,634,767 and has proposed a significantly reduced revenue requirement increase of approximately $17,443,000. Based upon the OTS proposed revenue requirement increase and the concept of gradualism, OTS believes that decreasing the Company's proposed increase in the residential minimum monthly charge from $7.20 to $5.90 (along with other OTS recommended rate design proposals) would adequately meet the Company's overall revenue requirement, while fully supporting the Company endorsed 12 CP cost of service study. This is especially true if the Company is granted an increase in this proceeding that is significantly lower than the increase requested by PP&L. Consequently, Mr. Kasper's concern about spreading the remaining customer costs over too large of a customer energy use base, would not be applicable under the OTS recommended revenue requirement increase.

Q. DO YOU HAVE ADDITIONAL COMMENTS CONCERNING THE COMPANY'S REJECTION OF A MINIMUM MONTHLY CHARGE THAT IS LESS THAN ITS PROPOSED $7.20?

A. Yes. Mr. Kasper has stated that PP&L has not filed a base rate case increase in 10 years and that an increase in the customer charge of $2.40/month would not cause an undue hardship on the vast majority of residential ratepayers and cause them to ration access to the electric system. (PP&L Statement 8-R, page 7). However, PP&L had the option to file a base rate case within the last ten years if it believed it was entitled to an increase. A determination of whether the proposed increase in the customer charge is too high should be based upon the concept of gradualism and whether the charge is consistent with the minimum monthly charges of similarly situated electric companies in Pennsylvania, as I stated in my initial testimony in this proceeding. (OTS Statement 3, page 4, OTS Ex. 3, Schedule 1). Moreover, I believe that PP&L's proposed $7.20 minimum monthly charge might cause a hardship for some of its customers.

Q. WHY DO YOU BELIEVE PP&L'S PROPOSED INCREASE TO ITS MINIMUM MONTHLY CHARGE MIGHT CAUSE A HARDSHIP FOR SOME OF ITS CUSTOMERS?

A. Since electricity is essential in modern life, any additional charges for that service will cause concern among a segment of the Company's ratepayers. Rationing of usage by these customers is a reality that must be recognized.

Q. MR. KASPER STATES THAT PP&L'S PROPOSED $7.20 MINIMUM MONTHLY CHARGE WOULD NOT BE THE HIGHEST IN THE STATE. IS THIS TRUE?

A. Yes, this is true based upon an OTS review of minimum monthly charges for electric utilities (OTS Exhibit No. 3, Schedule 1). However, it is also true that the $7.20 minimum monthly charge proposed by the Company would be the second highest rate among electric utilities in Pennsylvania.

Q. BASED UPON THE OTS REVIEW OF MINIMUM MONTHLY CHARGES, WHERE WOULD THE OTS PROPOSED $5.90 MINIMUM MONTHLY CHARGE RANK AMONG OTHER ELECTRIC UTILITIES IN PENNSYLVANIA?

A. It would be ranked fifth among the eleven electric utilities reviewed.

Q. WHAT IS THE COMPANY'S RESPONSE TO THE OTS PROPOSAL THAT AN INVESTIGATION OF THE RESIDENTIAL SERVICE - THERMAL STORAGE (RATE SCHEDULE RTS) BE HELD TO DETERMINE WHETHER THIS SERVICE WAS OFFERED WITH INFLATED PROMISES?

A. Mr. Kasper states that there was a perception problem among its RTS customers resulting from a letter that was sent to them in late March which confused the customers about the true rate increase for RTS customers. A second letter was then sent to resolve this confusion among the RTS customers. Therefore, the Company believes there is no basis for an investigation of Rate Schedule RTS. (PP&L Statement 8-R, page 24.

Q. DO YOU BELIEVE THAT AN INVESTIGATION OF RATE SCHEDULE RTS REMAINS NECESSARY?

A. Yes. The questions which remain to be answered are: (1) What, if any, promises were made to these customers?; (2) Under what conditions were any such promises made?; (3) Whether any savings were promised over a specific time period? and, (4) Whether representations were made as to how long it would take to recover the investment required to obtain RTS service?

Q. HAS THE COMPANY MADE ANY CHANGES TO ITS ORIGINAL PROPOSAL TO ADDRESS THE RATES FOR RATE SCHEDULE RTS?

A. Yes. Mr. Kasper states that PP&L intends to begin a pilot program with the installation of control devices on some RTS customers' facilities for testing purposes. As a result, the Company has proposed the following at page 12 of Mr. Kasper's Statement 8-R:

(1) Applications for service under the current Rate Schedule RTS will be accepted only through December 31, 1995.

(2) After December 31, 1995, customers wanting to use an electric thermal storage system will be eligible under a new rate schedule incorporating newer technology, appropriate terms, conditions and rates.

(3) Customer locations served under Rate Schedule RTS will continue to receive service under that rate during the life of the currently installed thermal storage system. The Company will not propose to reduce the existing 2.9 cents per KWH differential between RS and RTS customers before December 31, 1999.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED CHANGES TO RATE SCHEDULE RTS AND THE OFFERING OF A NEW RATE SCHEDULE FOR ELECTRIC THERMAL STORAGE SYSTEMS?

A. I agree with the closing of Rate Schedule RTS on December 31, 1995 and that RTS service will be offered only during the life of the currently installed thermal storage system. Concerning the offering of a new rate schedule for electric thermal storage systems, a thorough review would be needed by the Commission to determine its acceptability.

Q. MR. KASPER HAS TESTIFIED IN HIS REBUTTAL TESTIMONY THAT YOUR PRESENTATION OF THE COMPANY'S PROPOSED PERCENTAGE INCREASE FOR RATE SCHEDULE SE, ENERGY ONLY STREET LIGHTING SERVICE, INVOLVES CHANGES IN BASE RATES ONLY. IS THIS CORRECT?

A. No. At page 1091 of the transcript, I provided a correction to my OTS Statement 3, page 15 such that the total revenue percentage change for Rate Schedule SE after the proposed ECR and Base Rate Credit Adjustment have been included, would be 20.49 percent. Therefore, there is no difference in my calculation of the percentage increase for Rate Schedule SE and the Company's witness, Mr. Kasper.

Q. **ARE THERE OTHER AREAS OF DISAGREEMENT WITH THE COMPANY CONCERNING RATE SCHEDULE SE, ENERGY ONLY STREET LIGHTING SERVICE?**

A. Yes. I disagree with Mr. Kasper's statement that Rate Schedule SE should not be considered an off-peak rate since it is on peak 5 months out of a 12 month period and that I did not present any evidence that the proposed increase to Rate Schedule SE could place a financial strain on a given community. (PP&L Statement 8-R, pp. 46-47).

Q. **PLEASE STATE THE REASONS WHY YOU BELIEVE RATE SCHEDULE SE SHOULD BE CONSIDERED AN OFF-PEAK SERVICE?**

A. In Exhibit No. 3, Schedule 3, page 2 of 2, I demonstrate that 7 months out of 12 months the monthly system peak occurs during daylight hours and the 62 KW that is attributable to street and area lighting during on-peak periods is due to traffic lighting only. Moreover, this schedule demonstrates that on a total 12 month average, the total street lighting and area lighting contributes .2% of demand on the total system. Based upon this data, in my opinion the majority of the time street lighting is an off-peak service. An investment in metering equipment to determine off-peak and on-peak periods would not be necessary, since the Company has been providing street lighting service for many years. Historical data should be available for on-peak and off-peak periods.

Q. HAS THE COMPANY STATED ANY OTHER REASONS WHY RATE SCHEDULE SE SHOULD NOT BE CONSIDERED AN OFF-PEAK RATE?

A. Mr. Kasper states that off-peak rates are generally for customers who can shift load to off-peak periods and that street lighting does not have that flexibility. (PP&L Statement 8-R, page 47).

Q. DO YOU FIND THIS REASON TO BE AN OBSTACLE TO RATE SCHEDULE SE BEING CONSIDERED AN OFF-PEAK RATE?

A. No. The ability to shift load is not the only criteria to determine whether a service is on-peak or off-peak. As I have previously testified, a determination can also be made based upon whether the service is primarily used during on-peak or off-peak periods. I have demonstrated that street lighting primarily occurs during off-peak periods of the year. (OTS Ex. 3, Schedule 3, page 2). The change can be accomplished with a tariff filing which provides an on-peak rate for the five winter months and a (lower) off-peak rate for the remaining seven months (April through October).

Q. HAS ANYONE STATED THEIR CONCERN FOR THE INCREASE IN RATE SCHEDULE SE OR STREET LIGHTING IN GENERAL AND ITS EFFECT ON THE COMMUNITY?

A. Yes. The rates for street lighting in general is a concern as witnessed in the various public input hearings held throughout the Company's service territory. For example, Mr. John Cawley from the City of Scranton (Public Input Tr. 376) mentions the budget shortfalls of municipalities and cities and the effect the street lighting increase will have on their budgets. Similar concerns were expressed in the City of Wilkes Barre (Public Input Tr. 405 and 413), City of Hazleton (Public Input Tr. 465) and City of Bethlehem (Public Input Tr. 629). Therefore, although I did not provide financial data showing the ill effects of increases in Rate Schedule SE on the budgets of cities and municipalities, testimony provided by council members and citizens along with their concern with increases in the street lighting rates, demonstrates that the impact on these communities will be significant.

Q. WHAT COMMENT HAS OFFICE OF CONSUMER ADVOCATE WITNESS DR. CHARLES JOHNSON MADE CONCERNING YOUR TESTIMONY?

A. Dr. Johnson's primary concern appears to be the fact that I have supported the Company proposed 12 CP cost of service study. (OCA Statement 3A, pp. 11-12). However, I believe that the 12 CP cost of service study best represents the costs attributable to each of the services provided by PP&L. This is why I have proposed a significant increase for the RTS class if an increase is granted. As indicated in my initial testimony, the RTS class is showing a negative return under the 12 CP cost of service study. See OTS Ex. 3, Schedule 2. Dr. Johnson's criticism of my proposed increase to the RTS customers is curious because the cost of service study that he supports also shows a negative return for the RTS class. See, OCA Ex. CEJ-1, Schedule 1, page 1 of 2.

Dr. Johnson also states that my simultaneous call for an investigation of the RTS class and a request for a large percentage increase to these customers is somehow inconsistent. (OCA Statement 3A, page 11). However, Dr. Johnson fails to understand that the identification of the appropriate increase for the RTS class based upon the appropriate cost of service study, is separate from the question of whether inflated promises were made to RTS customers to induce them to purchase the service. Thus, there is no inconsistency between calling for an investigation of the RTS class and proposing that these customers pay their fair share until all questions are answered to the satisfaction of the Commission.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

OSBA Statement No. R1 & Ex R-1 thru R-7
5/25/95 Hrg

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-00943271
PENNSYLVANIA POWER & LIGHT COMPANY	:	

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Rebuttal Testimony and Exhibits of
ROBERT D. KNECHT

On Behalf of the
Office of Small Business Advocate

Date Served: May 9, 1995

Date Submitted for the Record: ______________

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REBUTTAL TESTIMONY OF ROBERT D. KNECHT

Q. Please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I prepared and filed direct testimony in these proceedings. My résumé and schedule of appearances before regulatory authorities were attached to my direct testimony as Appendix A.

Q. What topics does this rebuttal testimony address?

A. This testimony addresses some of the cost allocation and rate design proposals of various intervenor witnesses. Specifically, this testimony addresses:

- The cost allocation proposal for generation demand costs of Witness Johnson;
- The cost classification/allocation proposals for certain distribution system costs of Witnesses Andersen and Johnson;
- The cost allocation and rate design treatment of interruptible service proposed by Witnesses Johnson, Brubaker, and Baron;
- The implications of increasing competition in the supply of electrical energy for rate design in these proceedings, as raised by Witnesses Brubaker and Baron;
- The revenue requirement assignment schemes of Witnesses Johnson and Baron; and

- The proposals for re-allocation of a reduced revenue requirement of Witnesses Baron and Yarolin.

In addition, this testimony includes a proposal for assigning the revenue requirement amongst the classes in the event of (a) substantial reductions in the necessary revenue increase, and (b) a reduction in the jurisdictional revenue requirement relative to current rates, as suggested by Judge Christianson (Tr. 1106). The balance of this testimony is organized into the functional categories listed above.

Allocation of Generation Demand Costs

Q. Please summarize the proposals of the various intervenor witnesses regarding the appropriate allocator for generation demand costs.

A. Witness Eisdorfer recommends the use of a single winter peak allocator (1 CP), and develops a revenue requirement recovery scheme based on that methodology. Witnesses Baron and Brubaker recommend the use of a winter peak allocator, but both adopt the monthly coincident peak allocator (12 CP) proposed by PP&L for their rate design recommendations. Witness Johnson proposes the adoption of a system load factor weighted peak-and-average allocator, using a 5 month coincident peak measure for the peak portion of the costs. Witness Andersen supports the proposed 12 CP allocator, and I did not contest the adoption of the 12 CP allocator in my direct testimony.

Q. Could you comment briefly on the cost causality considerations for selecting an allocator for generation demand costs?

A. In the most simple sense, electric utilities construct generating capacity to meet system peak demand requirements, with sufficient reserve to provide an acceptably low loss of load probability. Thus, it is common for cost allocation analysts to classify the fixed costs that are incurred to supply capacity to "demand," and to allocate those costs using each class' contribution to some measure of the system coincident peak. The selection of the appropriate measure of peak depends on a variety of factors that are specific to each utility, including the seasonality of the peaks, the relative magnitude of the off-season monthly peaks, the maintenance requirements of the various generating facilities, and the responsibility of the utility to any larger power pool in which it jointly plans. The relative importance of these factors mandates the use of judgment in the allocator selection, often resulting in disagreements amongst the various analysts. In this case, virtually all of the analysts support the use of some type of peak-based allocator, although there is disagreement as to which is best suited to PP&L. Dr. Johnson's proposal is the exception.

Q. Please summarize Dr. Johnson's rationale for his proposal for a peak-and-average allocator.

A. Dr. Johnson argues that energy considerations should be factored into the allocation of fixed demand costs, because, if peak demand were the only considerations for capacity investment decisions, generating plant would consist solely of low capital cost combustion turbine peaking plants. He selects the system load factor as the weight for the energy component of the allocator, relying, at least in part, on the logic of the equivalent peaker classification/allocation scheme. Dr. Johnson suggests that the capital cost for a combustion turbine is about 30 to 40 percent of the capital cost of a baseload coal plant, and therefore the energy weighting in the peak-and-average method should be about 60 percent. In effect, Dr. Johnson proposes to abandon the fixed-variable scheme for classifying generation costs, and to reclassify 61.05 percent of fixed costs to "energy-related."

Q. Do you agree with the use of peak-and-average or equivalent peaker schemes for the classification and allocation of generation demand costs?

A. No. Both of these methods contain an inherent logical flaw, in that they ignore the duality of the "capital for fuel tradeoff." Generation planners design an integrated system of various types of generating equipment to minimize total costs, not simply capital or fuel costs. If it can be argued that utilities expend higher capital costs in constructing baseload units to save fuel costs, it can equally well be argued that utilities expend substantially higher fuel costs for peaking units in order to save capital costs. Thus, following the logic of these methods, all fuel costs in excess of those needed to run, say, a baseload nuclear plant, should be classified to "demand-related" and allocated using a peak allocator. While there are cost classification/allocation schemes for <u>all</u> generation costs, including energy and capacity costs, that attempt to model the duality of the tradeoff, the fixed-variable approach used by PP&L is the most practical. These other methods require substantial data inputs for computing the allocators and can be sensitive to assumptions regarding relative fuel prices, which can fluctuate substantially between rate proceedings. Overall, the fixed-variable classification scheme reasonably reflects the duality of the fuel/capital tradeoff for generation planning.

Q. **Does Dr. Johnson's proposal have implications for rate design?**

A. Yes. By reclassifying a substantial amount of costs from "demand-related" to "energy-related," Dr. Johnson's proposal should affect the rate design for virtually every rate class except Rates R, RTS and the street and outdoor lighting rates. The GS, GH and LP classes have either explicit or implicit demand charges that are designed to recover a reasonable portion of the demand costs assigned to that class. By effecting a massive transfer of costs between these classifications, Dr. Johnson's proposal should result in substantial reductions in the demand charges for these classes. For example, PP&L's proposed rates for the LP-5/LP-6 class produce approximately 40 percent of total revenues, either directly through the demand charge or in the incremental energy charges for lower load factor service above the runout rate in the last block. PP&L's proposed demand charge revenue is generally consistent with its cost allocation study, which indicates that some 55 percent of costs are demand-related. (Most utilities design demand charges to under-recover demand costs, to better reflect diversity in metered demand vis-a-vis the cost-driving coincident demand contribution.) Because a very large share of the demand costs assigned to this class are generation-related, Dr. Johnson's proposal would result in the demand share of costs dropping below 25 percent. Dr. Johnson's proposal would also have significant implications for PP&L's proposal to establish a discount for interruptible service relative to firm. Unless the rate tariffs are substantially modified, Dr. Johnson's proposal creates a tariff with a severe reverse rate tilt. Unfortunately, Dr. Johnson's testimony provides no guidance in the area of reducing demand charges.

Q. What is your recommendation with respect to the various proposals for classification and allocation of fixed generation costs?

A. I recommend that PP&L's use of the fixed-variable scheme for classifying generation costs between the demand and energy classifications be approved, and that Dr. Johnson's proposal to reclassify a significant share of fixed costs to energy-related be rejected.

Classification of Distribution Plant

Q. Please summarize the alternative methodologies proposed in these proceedings regarding the classification of distribution costs between the "demand-related" and the "customer-related" classifications.

A. PP&L proposes that certain distribution plant and the associated O&M costs be split between the demand-related and customer-related classifications based on the minimum system method, as outlined in the NARUC Cost Allocation Manual. The plant accounts subject to the minimum system analysis include Accounts 364 through 369, which includes poles, conductors, transformers, and services. The percentage of costs assigned to the demand classification are allocated using a class non-coincident peak demand allocator. In general, costs classified to customer-related are allocated using an unweighted customer allocator. In the case of line transformers and service drops, PP&L's method incorporate a higher customer weighting for two-phase and three-phase service, effectively including a demand component into the allocation of those customer costs. Dr. Andersen proposes to reject the minimum system approach in favor of a 100 percent demand classification, for a subset of these accounts. Dr. Johnson proposes to accept the minimum system classification, but to modify the allocator used to allocate the demand portion of these costs, to exclude the demand that could be carried on the minimum system and thereby avoid double-counting.

Q. **Could you comment on Dr. Andersen's argument that PP&L has defined the minimum system incorrectly?**

A. Dr. Andersen notes that PP&L has utilized the cost of the minimum-sized equipment currently being installed on the system, instead of the minimum sized equipment actually in service on the system at present. While this comment is correct, PP&L has simply followed the dictates of the NARUC Cost Allocation Manual regarding industry practice for this methodology (See OSBA-28 which is included in Exhibit R7).

Q. **Can you address Dr. Andersen's concern that the minimum system method employed by PP&L double-counts the demand-carrying capabilities of the minimum system?**

A. Dr. Andersen argues that the minimum system concept is a purely hypothetical framework in which a cost analyst attempts to evaluate the cost of attaching a new customer to the distribution system, but without load carrying capabilities. As such, a minimum system built to serve a customer with a positive load will not reflect what a distribution system planner would do for zero load customers. He suggests that a zero-intercept study would ameliorate this double-counting problem.

As in Dr. Johnson's logic regarding generation costs presented above, Dr. Andersen ignores the duality of the demand/customer cost tradeoff for distribution system costs. If it can be argued that a zero load system serving all customers could be built at much lower cost than PP&L's minimum system, it can equally well be argued that PP&L could serve total secondary demand at a single location at much lower cost than those costs assigned to the demand classification. Both arguments represent extreme viewpoints for classifying distribution costs between demand and customer categories.

Q. **What are your views of the factors causing distribution system costs to be incurred, and the implications for classification and allocation?**

A. Both the minimum system and the zero intercept methods are attempts by utility cost analysts to equitably treat cost incurrence that is driven by a variety of factors, some of which do not readily lend themselves to class-by-class cost allocation. The factors that cause distribution system costs to be incurred extend beyond peak demand and number of customer considerations, and include geographic density of customers, system reliability concerns, existing equipment constraints, etc. Because of these additional factors, there is no theoretically correct way to classify costs into those two categories. From a common sense perspective, however, there are both demand and customer components to distribution system costs. For example, if the demands on the distribution system increase, with no change in the customer count, the capabilities of the equipment will need to rise as will the associated costs. This relationship is the one that is measured in the zero-intercept method, in a statistical analysis between costs incurred and the level of demand on the individual types of equipment. In most zero intercept analyses, the intercept term is positive, which indicates that the distribution costs are not 100 percent demand-related. Similarly, if the number of customers in a particular class increases (say, for example, a new residential development) without any class-wide increase in demands, costs will need to rise as poles, transformers, conduit and service drops will need to be installed. The minimum system analysis attempts to measure this impact, by judging the cost increase associated with adding new customers. In the ideal, I would consider the results of both types of approaches in designing rates. The zero-intercept method, however, requires data intensive, time consuming analysis, which is often avoided by both utilities and intervenors. To my knowledge, no party has filed a zero intercept study in these proceedings.

Q. **What is your reaction to the statistical analyses cited by Dr. Andersen that suggest that there is no statistical evidence regarding correlation between distribution costs and number of customers?**

A. Due to time constraints, I have not reviewed the specific 1975 study cited by Dr. Andersen. However, the factors cited earlier causing cost incurrence for distribution systems are specific to the individual utilities. As such, Dr. Andersen's cited study is not particularly relevant for PP&L in 1995. Also, econometric analyses of distribution system costs are likely to suffer from a variety of interpretation and statistical problems. If these analyses include other variables such as customer density in the econometrics, the effects of these other variables subsequently need to be assigned to the various customer classes on some measurable basis, to perform a cost allocation study. If these variables are excluded, the statistical results suffer from omitted variables econometric problems. Also, statistical analyses that include both demand and number of customers in the econometric specification suffer from an econometric problem of multicollinearity, due to the high correlation between customer count and demand. Finally, any analysis of distribution system costs needs to be of a long term and/or broad cross-sectional nature, to incorporate the effects of significant additions to the customer base to the analysis.

Q. But Dr. Andersen cites Professor Bonbright in support of his position. Are you arguing that Professor Bonbright is incorrect?

A. No. As Dr. Andersen acknowledged in cross-examination (Tr. 1309), Professors Bonbright, Kamerschen and Danielsen do not endorse a single specific solution to this problem. I have attached the full section from Principles of Public Utility Rates from which Dr. Andersen's citation is drawn as Exhibit R1. The textbook explicitly rejects Dr. Andersen's solution to the problem, namely assigning all costs to demand-related. In addition, Dr. Andersen disregards his own suggestion that a zero intercept study would eliminate the alleged double-counting problem, and does not present a zero-intercept analysis. Rather, he argues that reducing the minimum system to one based on the actual minimum sized transformer actually in use on the system, combined with an adjustment to the allocator applied to the demand component of the costs to eliminate the load carrying capabilities of the 3 kVA minimum system, would produce overall allocators similar to a 100 percent demand classification methodology with a non-coincident peak methodology.[1]

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[1] *Dr. Andersen asserts that, but for the street lighting classes, the results of his modifications and the 100 percent demand classification method, the overall allocators do not differ "appreciably." However, his table indicates*

Finally, I note that Professor Bonbright's text also states:

> *"In actual practice the vast majority of utilities utilize some form of minimum system to classify costs, which is in line with the FERC accounts."*

In short, <u>Principles of Public Utility Rates</u> does not recommend a specific procedure, but confirms that the minimum system/zero intercept methods are widely accepted and used.

Q. Mr. Knecht, what is your recommendation regarding Dr. Andersen's proposal for classifying distribution costs?

A. I recommend that Dr. Andersen's proposal to modify the cost allocation procedure be rejected as being inconsistent with cost causality. While alternatives to the minimum system approach can reasonably be considered in developing rates, Dr. Andersen's proposal represents an unreasonable extreme.

Q. Can you comment on Dr. Johnson's proposal regarding the minimum system approach posited by PP&L?

A. Dr. Johnson raises the identical issue of the "double-counting" of demand served by the minimum system as that raised by Dr. Andersen. Dr. Johnson, however, does not propose to convert to 100 percent demand classification, but instead computes an adjusted demand allocator for the demand-

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that the GS-3 class is allocated some 5 percent more under the 100 percent demand classification than under his adjusted version. As distribution plant represents some 25 percent of the net plant in service assigned to the GS-3 class, this difference at least approaches "appreciable."

related portion of the costs. At first blush, this adjustment would appear to be a more moderate approach, and one that might better reflect the results of a zero intercept study. Unfortunately, Dr. Johnson's implementation of this proposal is badly flawed, causing cost allocation results that are more extreme than Dr. Andersen's proposal.

Q. **Could you explain why you say the results are more extreme than Dr. Andersen's?**

A. As noted above, the minimum system and zero intercept methods are used to split distribution costs into demand and customer components. It usually goes without saying that the extreme bounds of the cost split are from 100 percent demand-related (as proposed by Dr. Andersen) to 100 percent customer-related. The effective allocator for each cost component then usually represents a weighted average of the demand allocator and the customer allocator, where the weights represent the customer and demand cost split. The effective weighting of Dr. Johnson's proposal is shown in Exhibit R2. Remarkably, the effect of his proposal is a negative customer weight, and a demand weight exceeding 100 percent, for all secondary distribution cost components save service drops. As an example, consider the case of allocating the costs of secondary overhead lines to the RS class. PP&L's minimum system study assigns 44.8 percent of these costs to demand-related and 55.2 percent to customer-related. Cost allocation to the RS class under PP&L's method includes 86.9 percent of the customer portion plus 56.9 percent of the demand portion, producing a weighted average share of 65.3 percent allocated to the RS class. Note that the 65.3 percent lies between the customer allocator (86.9 percent) and the demand allocator (55.2 percent). Under Dr. Johnson's method, however, 86.9 percent of the customer costs are assigned to the RS class, but none of the demand costs are assigned to the class. (Dr. Johnson's calculations indicate that the minimum system can serve more than the entire RS load.) On average, Dr. Johnson's proposal allocates 48.0 percent of the secondary overhead lines cost to the RS class, <u>a percentage that is less than both the customer and the demand allocator</u>. In effect, Dr. Johnson's method implies a customer component of *negative* 30 percent, and a demand component of 130 percent. As shown in Exhibit R2, this negative customer weighting applies to all of the distribution plant categories, save services.

Q. Why does Dr. Johnson's method produce such extreme results?

A. There are a number of methodological errors in Dr. Johnson's adjustments, which contribute to the skewed results. First, Dr. Johnson deducts the load carrying capability of the minimum system transformers from the class non-coincident peak demand. This approach assumes that total transformer capacity equals class non-coincident demand. It completely ignores the fact that some reserve capacity must be built into the system, to allow for demand growth, unexpected fluctuations in demand, etc. This assumption also ignores the geographical diversity built into the non-coincident peak demand allocator -- distribution systems need to be built to meet non-coincident peaks in each geographic area, and not simply the diversified sum of the peaks within a particular class. Second, Dr. Johnson makes no effort to adjust for the demand effect that PP&L builds into its CW8 allocator for the transformer component of costs, and, as such, is guilty of the very double counting he criticizes.[2]

Q. What is your recommendation with respect to Dr. Johnson's proposal for distribution cost classification?

A. I recommend that Dr. Johnson's proposal be rejected, and that PP&L's minimum system approach be adopted as the most reasonable of methodologies posited in these proceedings.

Cost Allocation and Rate Design for Interruptible Service

Q. What are the important considerations for allocating costs to interruptible customers?

A. In the cost allocation process, it is important to recognize that system planners do not include the demands of

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[2] *Dr. Johnson's workpapers (excerpt included in Exhibit R7) are a little confusing on this topic. While on page 21 of his workpapers, he appears to have eliminated the weighted customer allocators CW8 and CW9, implying that he does not use them in the calculations, the actual allocations of line transformers and services utilize PP&L's CW8 and CW9 weighted customer allocators. (See p. 1 of workpapers).*

interruptible customers in determining the capacity necessary to meet the peak demand load. Utility planners do, however, consider the expected annual energy needs of interruptible customers, except during the limited number of hours for which interruption is allowed. Including interruptible energy requirements in planning can cause a different mix of generating capacity to be constructed than had those customers been firm. Cost causation for interruptible customers is therefore different than for other customer groups. Other customers generally have only the option to take service or not to take service. Costs caused by those customers represent the cost difference between providing the service and not providing it. Interruptible customers have a third option, namely taking firm service instead of interruptible service. The costs caused by interruptible customers can be seen as either (a) the difference between the costs of supplying and not supplying the customer, or (b) the difference in costs between supplying the customer with interruptible service and with firm service. Unfortunately, these two different methods typically produce substantially different costs to be assigned to the interruptible customers. The difference in results between these two alternatives is the primary factor causing the enormous differences between the proposals of the various cost analysts in these proceedings.

Q. Can you describe why these alternatives produce such different results?

A. I have attempted to do so pictorially in Exhibits R3 and R4. Exhibit R3 depicts a simplified load duration curve for an electric utility, that plans to meet its load with some combination of baseload capacity and peaking capacity. The breakeven capacity factor between baseload and peaking plant operation is denoted CF0. At time 0, the LDC consists of firm and interruptible demand, and the optimal capacity levels are defined as B0 and P0 respectively. (For simplicity, the reserve margin is set to zero in this example. In this idealized planning world, the reserve capacity would consist solely of peaking capacity.) As shown, the peak is flattened to reflect the ability to interrupt load. The dotted line represents the increase in load associated with a conversion of the interruptible load to firm. As shown, this capacity will be then not be available for interruption during peak periods, increasing the overall capacity requirement. However, the peak shaving effect of the interruptible service avoids only peaking capacity investments. As shown, the total change in required capacity is supplied entirely by an increase in peaking capacity (P0 to P1). Thus, any savings should be based on the avoided peaking capacity costs, including associated reserve capacity requirements and fixed O&M costs.[3]

On the other hand, Exhibit R4 depicts the impacts on costs if, instead of converting to firm service, the interruptible load exits. In this case, there is no impact on the overall system capacity requirements, but the need for baseload capacity decreases (B0 to B1) while the need for peaking capacity increases by a like amount. The costs caused by interruptible service in this circumstance are therefore the difference between baseload and peaking capacity costs, including fixed O&M costs.[4] Thus, because there are these different options, analysts utilize a variety of different methods for allocating costs to interruptible customers.

Q. In a cost allocation study, does it matter whether interruptible customers are identified in a separate class from firm service customers?

A. Technically, it shouldn't make a difference. However, in practice, it is necessary to exercise caution if interruptible customers are combined with firm customers. If there is a significant mismatch between costs assigned to interruptible

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[3] *A fuel cost adjustment should also be made to recognize that the avoided fuel costs during the peak periods is generally less than the avoided energy charges observed by the interruptible customer. If the capacity factor of the incremental peaking capacity is low, due to constraints on the interruptibility of customers, this adjustment is relatively minor.*

[4] *Note that this result is different than that produced by the exit of a firm customer, which would cause an overall reduction in capacity, generally consisting of some combination of baseload and peaking facilities.*

customers and the rates that are provided by those customers, it can be incorrectly inferred that rates and costs for firm customers in that class are out of balance. For that reason, I agree with Mr. Brubaker's recommendation that interruptible service be treated as a separate class for the purposes of cost allocation. In that way, the selection of a particular cost allocation method for interruptible service will not pollute the costs allocated to the other classes. Rates for interruptible service can be established using all of the relevant criteria for interruptible rate design, including, as appropriate, allocated costs.

Q. **What are the relevant considerations for rate design for interruptible service?**

A. From my perspective, a variety of considerations should be included when designing interruptible rates -- it should not be a cut-and-dried cost-based procedure. First, allocated costs should be considered, but I would include costs defined as both the cost of avoided peaking capacity and the costs produced by the conventional cost allocation results, wherein peak demand for interruptible service is set to zero. The relationship between the firm rate and the interruptible rate should be considered. The medium- to longer-term relative value of interruptible service to the utility should be considered, in terms of its ability to effectively use peak shaving capacity and its overall capacity shortfall/surplus situation. A utility in a period of excess capacity needs to balance the need to keep customers from free-riding virtually firm service capacity on interruptible rates with its needs to maintain an interruptible customer base that it can rely on when capacity is tight. Finally, the degree of interruptibility is an important consideration in developing rate discounts from firm service, and between different types of interruptible service.

Q. **As a contrast to the proposals of the various intervenors, can you briefly summarize PP&L's proposed approach for cost allocation and rate design treatment of interruptible service?**

A. In its cost allocation study, PP&L treats interruptible load as firm load for allocating costs, and then provides a $300 per kW rate base credit for the interruptible load. The $300 credit is established based on the costs of a new combustion turbine peaking unit. In its rate design, PP&L is proposing two different capacity credits for optional interruptible power for the LP classes, one set at $6 per kW per month and one, available to only LP-6 customers, at $8 per kW per month for 10 MW loads and a 30 minute notice.

Q. **Can you summarize Dr. Johnson's proposal for interruptible cost allocation and rate design?**

A. Dr. Johnson proposes to reduce the credit of $300 per kW defined by PP&L to a lower value of about $62 per kW, as an estimate of the current market value of the PJM capacity credits. As such, Dr. Johnson is applying the same basic logic as PP&L, but is choosing an extreme low-end value. He appears to accept PP&L's proposal to set interruptible discounts from firm service, or at least he posits no alternative to PP&L's proposal (page 18 lines 16-19). As noted above, I agree there is no reason for exact matching of costs and rates. If there is a difference, however, there is the danger in rate design of ascribing the revenue excess or shortfall only to the customers within those classes with interruptible customers. Dr. Johnson has not corrected for this problem in his rate design procedure, and therefore effectively ascribes the interruptible customers' shortfall to the firm customers within those classes. Moreover, I disagree with Dr. Johnson's reasoning about costs and rates. Dr. Johnson argues that the cost allocation study should reflect short-term value of peaking considerations, while rates can be more reflective of the longer term. It makes more sense to reflect the longer term cost considerations in the cost of service study, and to modify rates to reflect shorter-term considerations, where judgment is of greater importance.

Q. **Can you summarize Mr. Brubaker's positions on interruptible service cost allocation and rate design?**

A. Mr. Brubaker advocates the assignment of no fixed capacity costs to the interruptible customers, as if the only options for interruptible customers were to take interruptible service or to take no service. This methodology tends to represent the high-end of valuing the interruptible service discount, at least under current economic conditions facing PP&L.[5] While Mr. Brubaker does recommend preparing the cost allocation study with a separate interruptible class or classes, the study he presents does not do so. As such, interpreting his study needs to be done equally carefully, to make sure that the over-recovery of allocated costs from the interruptible customers does not solely benefit the firm customers within those classes. Based on his cost analysis, Mr. Brubaker recommends that the existing differential between firm and interruptible rates be maintained. For the reasons outlined, this cost basis tends to overstate the cost differential between firm and interruptible service. Mr. Brubaker's own exhibits also demonstrate that PP&L's existing differential between firm and interruptible rates is quite high compared to the Midwestern utilities in his survey. Exhibit R5 demonstrates that PP&L's existing interruptible discount from firm service is fourth highest of the utilities surveyed both on a mills per kWh basis and as a percent of the cost of firm

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[5] *In some utilities under economic conditions not very long ago, the average embedded cost of capacity was not significantly greater than the incremental cost of peaking capacity, and the two methods produced similar results. Such is not the case presently for PP&L, where average embedded capacity costs far exceed the incremental cost of peaking capacity.*

service. Finally, it is my understanding that the interruptible discount relative to firm service was substantially increased in 1992, without a cost of service study analysis. The combination of these factors leads me to conclude that the existing interruptible discount from firm service is too high, and Mr. Brubaker's proposal should be rejected.

Q. **Can you comment on Mr. Baron's approach to interruptible service cost allocation and rate design?**

A. For cost allocation, Mr. Baron maintains consistency with rate design. He sets the credit in the cost allocation study equal to the credit utilized in the rate design, thereby avoiding over- or under-ascribing costs to the firm customers within those classes. For the purposes of rate design, Mr. Baron indicates that his proposal produces an inherent interruptible credit that is "approximately the same as" that proposed by the company. He also provides calculations of (a) the official PJM capacity deficiency rate, and (b) 50 percent of the average embedded costs for generating capacity per unit of LP-5 billing demand,[6] that at least generally indicate that the magnitude of PP&L's proposed discount is reasonable.[7]

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[6] *Mr. Baron's computation of the discount would be somewhat lower if he used the PPLICA revenue requirement and rate of return recommendations, and had he used the 1 CP cost allocation methodology.*

[7] *Mr. Baron calculates that the effective interruptible discount in his proposal is $7.10 per kW (Tr. 1204). The weighted average LP-5/LP-6 discount from PP&L's proposal is $6.65 per kW of interruptible demand.*

Q. Could you comment briefly on the issues of competition raised by Witnesses Brubaker and Baron?

A. Both witnesses cite competition as the most critical of the current trends affecting the electric utility industry, and they indicate that PP&L's industrial rates are not competitive in today's market. While both claims are probably true, they have only limited relevance for setting rates <u>for specific rate classes</u> in these proceedings. There are two generic types of competition for industrial customers by power generators. First, generators can try to induce industrial customers to construct new facilities or to relocate plant production to sites with lower cost power. Second, the regulatory process may be modified to allow customers to purchase power on the open market from any generator they choose, requiring the local utilities to provide transmission and, if necessary, distribution systems. Competition in the former case has always existed, and is one of the reasons behind the EDI/IDI programs that PP&L had developed. Moreover, it is my understanding that PP&L offers a "competitive rate rider" that is structured to address this type of competitive situation for specific plants and companies. As to the second issue of competition, deregulation of generation may have substantial benefits to all customers in the form of higher efficiencies, better cost controls, and a more equitable spread of rates between utility franchise areas. There are, however, a few knotty problems yet to be solved. The non-technical problems include the issues of who pays for stranded capacity, how to convince customers now served by low cost utilities that competition will benefit them, and how will utilities charge for transmission services. Absent a solution to these problems and a comprehensive plan to convert to a deregulated environment for generation, competition should not be used to justify lower rates for entire classes of industrial customers. If PP&L has capacity that would be stranded in the event of deregulation, these costs should not be assigned to and recovered from the residential and smaller commercial classes, simply because deregulation may come someday. Similarly, of course, regulators need to be wary about utilities front-loading costs into current revenue requirements so as to avoid having to incur those costs when facing market prices.

Q. **What are your overall conclusions from your review of the intervenor evidence regarding interruptible cost allocation and rate design evidence?**

A. Overall, the magnitude of the discounts from firm service proposed by PP&L for interruptible service are generally reasonable on a cost basis, and reasonably reflect the other criteria for interruptible rate design cited above. Further, as shown in Exhibit R5, Mr. Brubaker's comparison of rates for Mid-Western utilities indicates that PP&L's proposed discount for interruptible service relative to firm (even after a substantial decrease) is relatively high, reflecting PP&L's generally higher rates.

Assigning the Revenue Requirement

Q. Do you agree with Dr. Johnson's proposal for assigning the revenue requirement to the various customer classes?

A. No. Dr. Johnson indicates that he bases his revenue requirement on his modified version of the PP&L cost of service study. As described above, Dr. Johnson's study relies on methodologies that do not reflect cost incurrence factors in the areas of generation demand costs, distribution plant, and the avoided costs of interruptible service. Based on this review, I recommend that Dr. Johnson's proposal be rejected. Any one of the changes that Dr. Johnson proposes to PP&L's cost allocation study creates cost allocations errors significant enough to reject his proposed allocation of the revenue requirement. Moreover, even if Dr. Johnson's cost allocation study were reasonable, I would disagree with his proposal with respect to the GS-1 class. Although Dr. Johnson's various proposals result in an increase in the indexed rate of return for the GS-1 class to 227.1 percent from 197.2 percent in the PP&L study, Dr. Johnson recommends a higher rate of increase for that class than does PP&L (5.9 percent as compared to 3.9 percent). In cross-examination, Dr. Johnson admitted that he did not rely on the relative costs of service for the GS-1 class produced from his study for setting rates, but has simply calculated the necessary revenue from the commercial classes as a residual (Tr. 1389, lines 17 to 22). I do not agree that this procedure is an acceptable way to assign revenue requirements to particular classes.

Q. **Do you have any major disagreements with respect to Mr. Baron's allocation of the revenue requirements?**

A. In light of the substantial reduction effectively awarded only to large interruptible customers in PP&L's June 1992 tariff modification, I disagree that the gradualism criterion for rate design provides justification for a 1.5 times system average cap on the increase for the interruptible "class," particularly in the event of a substantial reduction in the overall deficiency as proposed by other PPLICA witnesses.

Assigning a Reduced Deficiency

Q. **For the sake of clarity, can you define what you mean by assigning a reduced deficiency?**

A. A deficiency is the dollar value of the increase in revenues to be recovered from a class or classes. PP&L has proposed a system-wide deficiency of $262 million, and has proposed a method to recover that deficiency from the various rate classes. In effect, PP&L has proposed an assignment of the deficiency, by defining how it intends to recover revenues from each of the classes. Mr. Baron and Dr. Johnson have also proposed their own "deficiency assignments," but still based on PP&L's $262 million system-wide figure. If, however, the Commission approves a different deficiency than $262 million (typically a lower figure), some methodology must be adopted to produce a deficiency allocation for the new overall deficiency. Typically, the Commission will approve some proposal for the $262 million deficiency assignment, and the utility or the Commission will adopt some arithmetic adjustment to assign the reduced deficiency to the various classes.

Q. **What have you concluded regarding Mr. Baron's proposal for a method for assigning a reduced deficiency?**

A. Mr. Baron proposes that his revenue requirement assignment should be used as a starting point, and that any reduction in the deficiency should be scaled proportionately to the new deficiency. This method has the advantages that it is traditional, well-understood, and simple. As described in my direct evidence, this methodology unfortunately reduces the progress toward cost-based rates inherent in the original proposal. For that reason, I believe that the proportional scaleback should not be used. In Mr. Baron's proposal, this problem is particularly acute for treating the interruptible class of customers. If a proportional scaleback is used, particularly for a large reduction in the deficiency, and the interruptible customers are treated as a separate class, the effective interruptible discount for firm service will rise back to its current unacceptably high levels. If such a scaleback is used, it should be based on the aggregate for firm and interruptible customers within the relevant classes, and the interruptible discounts proposed by PP&L should be maintained. In the event of a substantial reduction in the overall deficiency, this procedure could require reductions in rates for firm industrial customers and increases in rates for interruptible customers.

Q. **How does Mr. Baron's proposal compare with your weighted scaleback proposal, in the event of a relatively small deficiency?**

A. At very low overall deficiency levels, such as the $20 million figure cited by Mr. Baron, the proportional scaleback method will not produce significantly different results than the "weighted scaleback" approach I proposed in my direct testimony. My weighted scaleback proposal allocates a reduction in the deficiency as a weighted average of two methods: the proportional scaleback method and the constant percent differential method. The weight for the constant differential method is the ratio of the approved deficiency to the original deficiency. As this ratio declines to very small values, the relative importance of the constant percent differential method declines, producing results very similar to the traditional proportional scaleback method. The weighted scaleback proposal is helpful for maintaining some reasonable progress toward cost-based rates only if the approved deficiency is a reasonable fraction of the original deficiency.

In general, if only a small positive deficiency is approved, any method that tries to have all classes contribute to that small deficiency will produce very little variation in rate increases amongst the classes and very little progress toward cost based rates. In such a circumstance, I strongly recommend that rate declines for some classes be found to be an acceptable assignment of the deficiency. Base rate cases are extraordinarily expensive and time consuming, and can be few and far between. The small business classes under present rates are currently subsidizing many of the other classes. Assigning very similar increases to all of the classes at this time simply perpetuates this inequity.

In the event of a very small positive deficiency, such that the deficiency is less than 25 percent of the original $262 million (about $65 million), I believe that the weighted scaleback proposal in my direct testimony can still be used, but I recommend that the weight for the constant percent differential be constrained to not decline below 25 percent. Thus, for any positive deficiency less than $65 million, the following formula can be used to derive a class' new deficiency:

(1) $D_i^* = .25 * [PCT_i - (PCT_s - PCT_s^*)] * CR_i + .75 * D_i * (D_s^* / D_s)$

where: D = Deficiency (proposed revenues - current revenues)

PCT = percent revenue increase (proposed revenues/current revenues - 1)

i = Rate class i

s = PP&L jurisdictional total

$*$ = Denotes that figure is based on reduced deficiency

CR = Current revenues

Note that the latter term on the right hand side of the equation is the proportional scaleback term, while the former term represents the constant differential term. An example of the weighted scaleback proposal using a 25 percent weight for the constant differential method is shown in Exhibit R6, based on a $50 million deficiency. The method produces a range of rate increases from 4.5 percent for the RTS class to -0.8 percent for the GS-1 class. Note that the percentage point spread between these two increases has declined significantly from PP&L's proposal of 13.5 points (17.4 percent minus 3.9 percent) to 5.3 points (4.5 percent minus negative 0.8 percent. While progress toward cost-based rates is reduced, gradualism considerations are factored in.

Q. Can you comment on the scaleback proposal of Mr. Yarolin?

A. At very low deficiency levels (below $17 million), Mr. Yarolin proposes that the entire deficiency be assigned to the RS and RTS classes. For any additional deficiencies above $17 million, Mr. Yarolin proposes that the proportional scaleback approach be used. For the reasons described above and in my direct testimony, I believe that the cost evidence supports rate reductions for some classes in the event of a small deficiency, and that the weighted scaleback approach is a better method for larger deficiencies. However, in the event that the Commission determines that no classes may receive a rate decrease <u>and</u> the approved deficiency is relatively small (less than $50 million), Mr. Yarolin's approach is a reasonable (if substantially constrained) effort to reduce the significant subsidy afforded the residential classes by the small business classes. As suggested above, I recommend that within this proposal, the existing interruptible discount relative to firm service be reduced.

Allocating a Negative Deficiency Amongst the Classes

Q. Would you respond to Judge Christianson's inquiry regarding the allocation of a negative deficiency amongst the classes?

A. I will try. In the event of a small negative deficiency, the policy question arises as to whether all classes should get a decrease, or whether some classes should get increases and others decreases. As in the case of a small positive deficiency, I recommend that the Commission utilize this opportunity to make progress toward cost-based rates by assigning substantively different percentage increases amongst the various classes, both negative and positive. In particular, as described above, the current discount for optional interruptible service relative to firm service is unjustifiably high, and should be reduced. Thus, it may be the case that interruptible customers see an increase in average rates, although the LP-5 class as a whole experiences a reduction.

Turning to the specific arithmetic, a proportional scaleback method simply doesn't work for a negative deficiency. Use of the proportional scaleback arithmetic would move classes away from cost-based rates, rather than toward a cost basis. The constant differential method does produce directionally correct results, but in the case of, say, a $50 million system-wide reduction, the constant differential approach would produce a range of rate changes from about -10 percent to +3 percent (see Exhibit R6). Although economically reasonable, such a broad band is typically not acceptable to public utility commissions, and, for that reason, I proposed the weighted scaleback version in my direct testimony. Unfortunately, because the weighted scaleback method relies on the proportional scaleback, it cannot be used without adjustment for a negative deficiency. While it's a little complicated, I propose an "adjusted weighted scaleback" mechanism in the event of a negative deficiency. In this method, the weighted scaleback arithmetic is applied as if the deficiency were positive, and percent increases for each class are calculated.[8] These increases are then reduced using a constant differential method to produce the final results. Exhibit R6 presents an example of how this procedure would work. In that example, a $50 million negative deficiency is hypothesized. The rate increases for each class are calculated using the weighted scaleback method (using PP&L's proposal as a starting point), producing rate increases as shown. For example, the RS class is assigned a 3.7 percent increase, while the GS-3 class is assigned a 0.3 percent increase. (Note that the proportional scaleback method produces 3.0 percent and 1.3 percent for those two classes respectively, while the constant differential method produces 5.8 percent and -2.8 percent.) Then, each class' percent increase is reduced by 4.6 percent, that being the percentage difference between a positive $50 million deficiency (+2.3 percent) and a negative $50 million deficiency (-2.3 percent). The resultant RS and GS-3 increases are therefore -0.9 percent and -4.3 percent respectively.

In addition to maintaining some reasonable amount of progress toward cost-based rates, this method has the advantage that, as the absolute value of the negative deficiency increases, the spread of percent changes between

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[8] *The 25% minimum weighting for the constant differential method should be utilized in this procedure, as recommended above.*

the classes also increases, further improving progress toward cost-based rates.

The arithmetic for this method is shown below, in two steps. The first step is virtually identical to equation (1) presented above for the weighted scaleback method, as applied to the absolute value of the negative deficiency. The second step applies the constant differential method to adjust the differential down from a positive deficiency to a negative deficiency.

(2) $D_i^* = w * [PCT_i - (PCT_s - PCT_s^*)] * CR_i + (1\text{-}w) * D_i * (ABS(D_s^*)/D_s)$

where:

D	=	Deficiency (proposed revenues - current revenues)
PCT	=	pct revenue increase (proposed revenues/current revenues - 1 = D/CR)
i	=	Rate class i
s	=	PP&L jurisdictional total
*	=	Denotes that figure is based on reduced deficiency
CR	=	Current revenues
ABS	=	absolute value function
w	=	weight for constant differential term = MIN(ABS(D_s^*)/D_s, 25%)

(3) $D_i^{**} = (D_i^*/CR_i - (ABS(D_s^*) - D_s^*)/CR_s) * CR_i$

A numerical example of this computation is presented below, based on the negative $50 million deficiency shown in Exhibit R6, based on the RS class:

(2) $D_i^* = .25 * (15.3\% - (11.8\% - 2.3\%)) * \$887.1 + .75 * \$135.6 * \$50/\$257.9$

$= \$32.5$ million

(3) $D_i^{**} = (\$32.5/\$887.1 - (\$50 - (-\$50))/\$2{,}182.4) * \$887.1$

$D_i^{**} = -\$8.2$

$PCT_i^{**} = -\$8.2/\$887.1 = -0.9\%$

Q. Does this conclude your rebuttal testimony?

A. Yes.

OSBA Exhibits

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-00943271
PENNSYLVANIA POWER & LIGHT COMPANY	:	

Exhibits of
ROBERT D. KNECHT

On Behalf of the
Office of Small Business Advocate

EXHIBIT R1

EXCERPT FROM PRINCIPLES OF PUBLIC UTILITY RATES

Principles of Public Utility Rates

Second Edition

by
JAMES C. BONBRIGHT
ALBERT L. DANIELSEN
DAVID R. KAMERSCHEN

with assistance of
JOHN B. LEGLER

Public Utilities Reports, Inc.
Arlington, Virginia

companies also allow for voltage differences and for distances between points of generation and consumption as well as for other clearly assignable cost elements. Other cost breakdowns — such as those allowing for the power factor and the customer-density factor — have been used to a limited extent. If the aforementioned threefold division of costs were to have its counterpart in the actual rates of charge for service, as it actually does have in some rates, there would result a three-part rate for any one class of service. For example, the monthly bill of a residential consumer might be the sum of a $5 customer charge, an $80 charge for 800 kilowatt-hours of energy at 10 cents per kilowatt-hour, and a $50 charge for a maximum demand of 10 kilowatts during the month at the rate of $5 per kilowatt — a total bill of $135 for that month. But our present interest lies in the measurement of costs of service, and only indirectly in rates that may or may not be designed to cover these costs. Let us therefore consider each of the three types of cost in turn, recognizing that this simplified classification is used only for illustrative purposes; costs actually vary in much more complex ways.

Customer Costs

Customer costs are those operating and capital costs found to vary with number of customers regardless, or almost regardless, of power consumption. Included as a minimum are the costs of the drop wire, metering and billing, along with whatever other nonrecoverable expenses the company must incur in taking on another consumer. In more general terms, they are the minimum service, metering, accounting, etc. costs of connecting another customer or the savings in costs of not connecting the customer. These minimum costs are substantially higher for large industrial users, who require more costly connections and metering devices than for residential and small commercial customers. While costs on this order are sometimes separately charged for in residential and commercial rates, in the form of a mere "service charge," they have been historically more frequently wholly or partly covered by a minimum charge which entitled the consumer to a very small amount of gas or electricity with no further payment.

Since PURPA in 1978, many electric companies have replaced the minimum monthly charge with a customer charge. This fixed charge is designed to cover the costs directly attributable to serving the customer class. However, there are those who argue that it represents an extreme version of declining block rates with the first unit of consumption bearing the entire burden of the fixed charge. Since PURPA prohibited declining block tariffs unless there were falling

energy costs — which was not likely since the standard operating procedure is to bring the lowest cost generating units on line first — this has been interpreted as representing an end run. These critics also argue that a customer charge may reduce social welfare, as the fixed customer charge amounts to a regressive head tax (see Renshaw and Renshaw, 1979). This is of course entirely beside the point from a cost allocation perspective.

The *FERC Handbook* (1983, p. 52) recognizes that while there are no hard-and-fast rules for allocating customer costs, as they depend on the type of costs involved, the issue is not usually litigated as the dollars involved are usually not substantial. The really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers, but also a substantial fraction of the annual maintenance and capital costs of the secondary (low-voltage) distribution system — a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage while keeping them from falling of their own weight. In any case, the annual costs of this phantom, minimum-sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary directly with the number of customers. Alternatively, they are calculated by the "zero-intercept" method whereby regression equations are run relating cost to various sizes of equipment and eventually solving for the cost of a zero-sized system (Sterzinger, 1981).

What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.

While, for the reason just suggested, the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to us clearly indefensible, its exclusion from the demand-related costs stands on much firmer ground. For this exclusion of minimum-sized distribution system costs makes more plausible the assumption that the *remaining* cost of the secondary distribution system is a cost which varies continuously (and, perhaps, even more or less directly) with the maximum demand imposed on this system as measured by peak load.

But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." They are therefore under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories.

In actual practice the vast majority of utilities utilize some form of minimum system to classify costs, which is in line with the FERC accounts. Sterzinger (1981) is critical of this practice and recommends that to avoid the overcollection of charges from low-use residential customers, regulators should classify distribution costs as demand costs. Neither of these procedures can be justified as a cost allocation in the sense of directly assignable costs, for they are in fact nonassignable.

Allocation, in whole or in part, would be at least theoretically possible if a customer-density parameter were added to the three traditional cost components. But if this factor were embodied, not only in cost analysis but in the resulting rate differentials, rates would not be uniform throughout a given community and hence would violate a generally accepted tradition (see Watkins, 1921, p. 212 and Havlik, 1938, Chapter 8 and Appendix A).

Energy or Unit-related Costs

The energy or unit-related costs components of this threefold division of total annual costs is supposed to consist of those costs which would vary with changes in the unit consumption of energy, measured in kilowatt-hours, even if the number of customers should

remain constant and even if there were no change in maximum loa upon the system or subsystem as measured by kilowatts or kilovol amperes. There is generally very little controversy — except fo projections of energy usage — with respect to the allocation of energ costs. The most obvious costs of this character are fuel costs, althoug a small portion even of these costs may be regarded as demand related on the ground that some fuel is required in order to maintai a "spinning reserve." But other operating costs may also be deeme to vary with output of power and hence with consumption of energy including whatever depreciation of the equipment may be regarded a a function of use rather than of obsolescence and aging.

Reduced to costs per kilowatt-hour, the imputed energy cost may be only a small fraction of average total costs. It is this relative smallness which is often held to justify a company in conceding ver low rates for off-peak or interruptible services, on the ground tha these services impose upon the company little or no additional capacit costs.

The treatment of energy costs as a separate cost function is subjec to one serious deficiency: namely, in its assumption that the cost t the company of producing any given amount of energy, measured i kilowatt-hours, is independent of the system load factor. For such a assumption may be belied by the fact that the generators which carr the company's base load will be much more efficient than those generators which are relied upon to carry the peak loads. Hence, th cost analysis may be in danger of overstating the relative energy cost of off-peak service and of understating the relative energy costs o on-peak service. Recognizing this danger, the analyst may undertak to offset it by imputing to the peak-time consumers a lower capacit cost than would otherwise be deemed justified — a capacity cos based on a steeply written-down net investment in, or appraised valu of, those older, less efficient generators that will be operated only fo a few hours per day. (See Brunetto, 1980, for a cost effective an reliable method of load research by electric utilities.)

About the only other controversy regarding energy charges i whether there should be a rate tilt. A *rate tilt* occurs where energ costs are counted as demand costs or vice-versa. According to th *FERC Handbook* (1983, p. 153) while these rate tilts have been accepte for years for gas pipelines, the Commission has usually rejected the in the rate designs of electric companies as it violates their stresse credo that rate design should reflect cost incurrence. However, cautio is warranted here, since capital costs may be incurred for the purpos of, and having the effect of, lowering energy costs. When a compan

EXHIBIT R2

DISTRIBUTION COST CLASSIFICATION
IMPLICATIONS OF PROPOSED OCA METHOD

	TOTAL	RS	RTS	GS-1	GS-3	GH	SL/AL
ALLOCATORS							
Customers -- C30	1,227,073	1,066,688	14,544	121,411	18,948	4,472	1,010
Meters Wtd. Customers -- CW8	1,475,214	1,080,235	14,671	165,519	49,196	8,274	157,319
Services Wtd. Customers -- CW9	1,413,615	1,074,207	14,614	134,564	27,373	5,538	157,319
PP&L Class Demand -- D30	5,971,000	3,396,000	265,000	465,000	1,590,000	228,000	27,000
OCA Class Demand	1,982,458	0	211,267	16,450	1,519,997	211,475	23,269
Customers -- C30	100.000%	86.929%	1.185%	9.894%	1.544%	0.364%	0.082%
Meters Wtd. Customers -- CW8	100.000%	73.226%	0.994%	11.220%	3.335%	0.561%	10.664%
Services Wtd. Customers -- CW9	100.000%	75.990%	1.034%	9.519%	1.936%	0.392%	11.129%
PP&L Class Demand -- D30	100.000%	56.875%	4.438%	7.788%	26.629%	3.818%	0.452%
OCA Class Demand	100.000%	0.000%	10.657%	0.830%	76.672%	10.667%	1.174%
ELECTRIC PLANT IN SERVICE -- OCA Allocation							
Secondary Overhead Lines	625,865	300,113	33,998	36,488	220,495	31,194	3,578
-- Demand (44.8%)	280,628	0	29,906	2,329	215,164	29,935	3,294
-- Customer (55.2%)	345,237	300,113	4,092	34,159	5,331	1,258	284
OCA Effective Allocator		47.952%	5.432%	5.830%	35.230%	4.984%	0.572%
Implied OCA Customer Weighting		-29.7%	-30.6%	-92.9%	-34.3%	-33.7%	-32.3%
Secondary Underground Lines	218,033	118,516	10,322	14,167	64,744	9,212	1,071
-- Demand (37.5%)	81,697	0	8,706	678	62,639	8,715	959
-- Customer (62.5%)	136,336	118,516	1,616	13,490	2,105	497	112
OCA Effective Allocator		54.357%	4.734%	6.498%	29.695%	4.225%	0.491%
Implied OCA Customer Weighting		-8.4%	-9.1%	-61.2%	-12.2%	-11.8%	-10.6%
Line Transformers	294,994	121,938	15,347	19,750	104,054	14,638	19,266
-- Demand (43.6%)	128,470	0	13,691	1,066	98,501	13,704	1,508
-- Customer (56.4%) - CW8	166,524	121,938	1,656	18,684	5,553	934	17,758
OCA Effective Allocator		41.336%	5.202%	6.695%	35.273%	4.962%	6.531%
Implied OCA Customer Weighting		-51.7%	-23.5%	-51.9%	-34.5%	-33.1%	-1643.5%
Secondary Dist'n Plant	1,764,757	840,680	93,665	106,893	609,789	86,237	27,493
-- Demand (43.7%)	771,423	0	82,209	6,401	591,468	82,290	9,055
-- Customer (56.3%)	993,334	840,680	11,456	100,492	18,321	3,947	18,439
OCA Effective Allocator		47.637%	5.308%	6.057%	34.554%	4.887%	1.558%
Implied OCA Customer Weighting		-30.7%	-26.7%	-82.1%	-31.6%	-30.9%	-298.9%

Implied customer weighting is defined as the weight that when applied to the C30 allocator combined with 1 minus that weight applied to the D30 allocator produces the effective OCA allocator. Algebraically:

$$w * C30\% + (1-w) * D30\% = OCA\%$$

$$w = (OCA\% - D30\%)/(C30\% - D30\%)$$

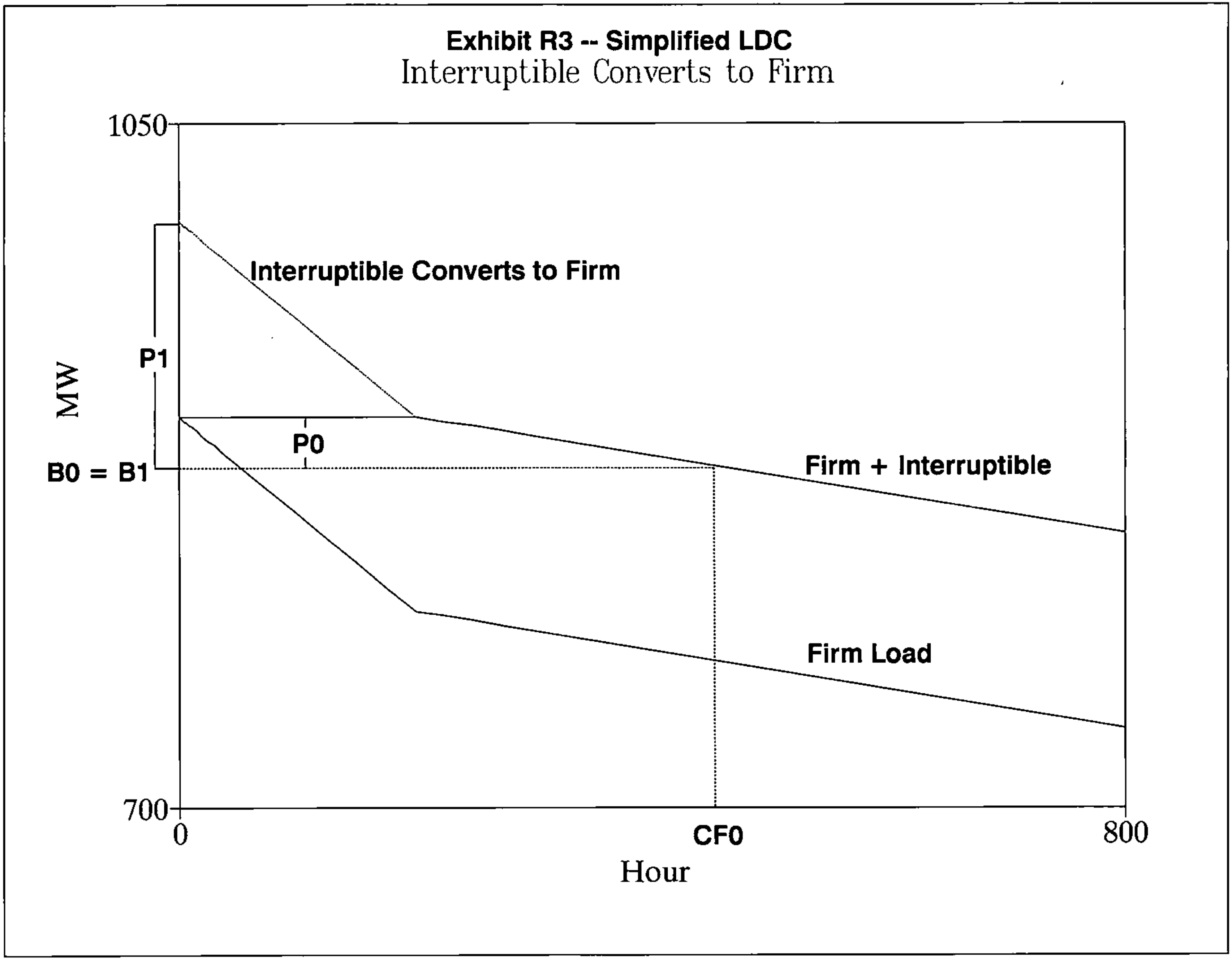
Exhibit R3 -- Simplified LDC
Interruptible Converts to Firm
1050
700
MW
P1
P0
B0 = B1
Interruptible Converts to Firm
Firm + Interruptible
Firm Load
0
CF0
800
Hour

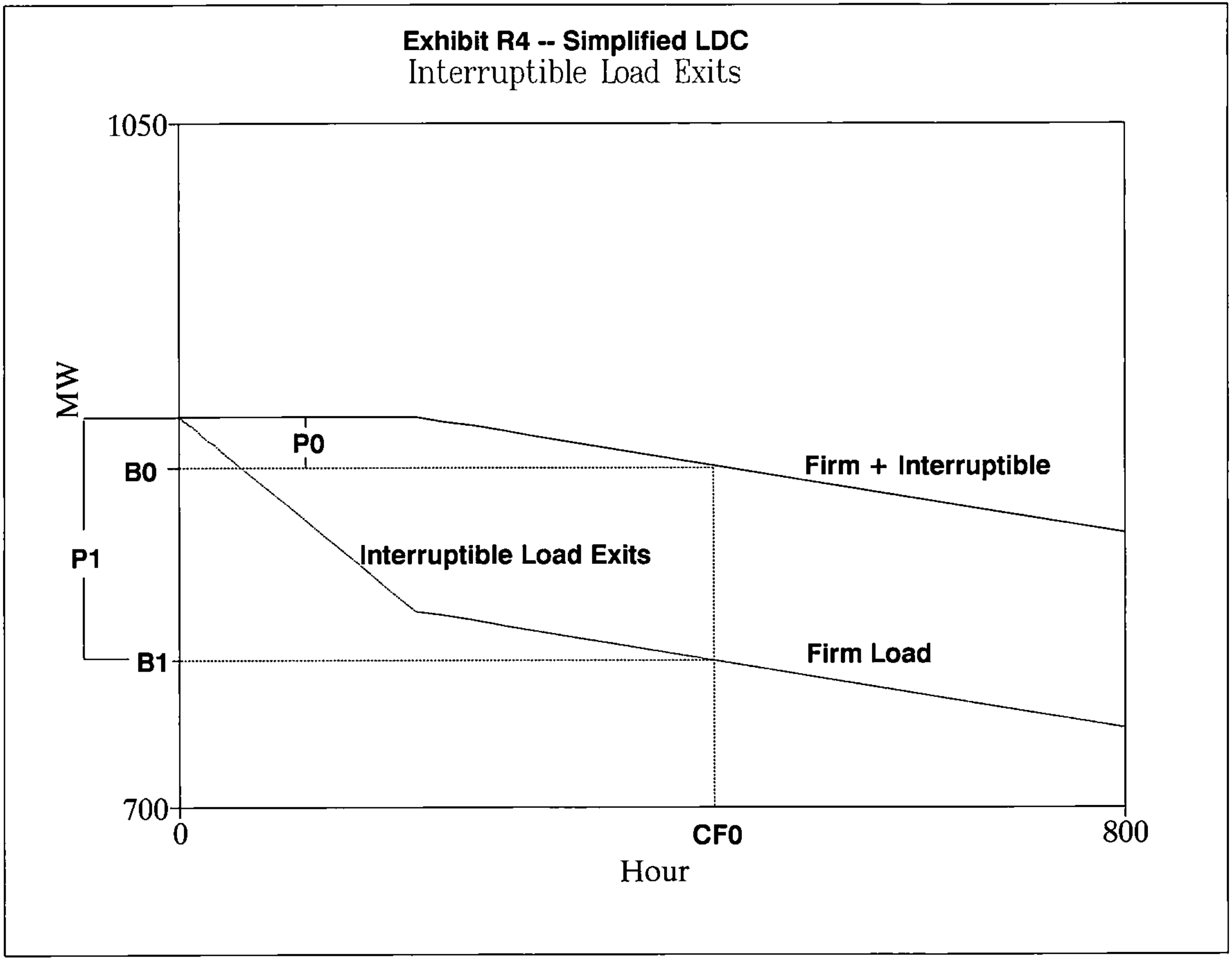
Exhibit R4 -- Simplified LDC
Interruptible Load Exits
1050
700
MW
P0
B0
P1
B1
Firm + Interruptible
Interruptible Load Exits
Firm Load
0
CF0
800
Hour

EXHIBIT R5

FIRM AND INTERRUPTIBLE RATES FOR INDUSTRIAL SERVICE
(12,000 kW; 68% Load Factor, 1994)

Utility	*Firm Mills/kWh*	*Interruptible Mills/kWh*	*Discount Mills/kWh*	*Eff. Discount $/kW/mo.*	*Percent Discount*	*Discount Rank*
Philadelphia Electric Company	81.12	37.24	43.88	$32.0	54.1%	1
Toledo Edison Company	81.18	50.04	31.14	$22.7	38.4%	2
Cleveland Electric Illuminating Company	69.75	39.89	29.86	$21.8	42.8%	3
Pennsylvania Power & Light -- Present	57.88	38.79	19.09	$13.9	33.0%	4
Illinois Power Company	55.67	39.53	16.14	$11.8	29.0%	5
Pennsylvania Power & Light -- Proposed	63.32	50.79	12.53	$9.1	19.8%	6
Pennsylvania Electric Company	50.53	39.22	11.31	$8.3	22.4%	7
Metropolitan Edison Company	55.05	44.13	10.92	$8.0	19.8%	8
Commonwealth Edison Company	55.91	45.06	10.85	$7.9	19.4%	9
Union Electric Company (IL)	41.98	31.20	10.78	$7.9	25.7%	10
Wisconsin Electric Power Company	40.35	30.62	9.73	$7.1	24.1%	11
Wisconsin Public Service Corporation	41.13	31.43	9.70	$7.1	23.6%	12
Cincinnati Gas & Electric Company	47.41	37.97	9.44	$6.9	19.9%	13
Consumers Power Company	54.65	45.39	9.26	$6.8	16.9%	14
Northern States Power Company (MN)	40.59	31.57	9.02	$6.6	22.2%	15
Indiana Michigan Power Company (IN)	46.27	37.69	8.58	$6.3	18.5%	16
Ohio Edison Co.	66.57	58.25	8.32	$6.1	12.5%	17
Detroit Edison Co.	64.20	56.00	8.20	$6.0	12.8%	18
Northern Indiana Public Service Company	63.23	55.04	8.19	$6.0	13.0%	19
Wisconsin Power & Light Company	38.74	31.06	7.68	$5.6	19.8%	20
Pennsylvania Power Company	55.97	48.44	7.53	$5.5	13.5%	21
Dayton Power and Light Company	49.90	43.32	6.58	$4.8	13.2%	22
Ohio Power Company	38.09	31.93	6.16	$4.5	16.2%	23
Northern States Power Company (WI)	45.68	39.87	5.81	$4.2	12.7%	24
West Penn Power Company	41.50	36.54	4.96	$3.6	12.0%	25
Duquesne Light Co.	63.39	59.18	4.21	$3.1	6.6%	26
Indiana Michigan Power Company (MI)	36.50	32.32	4.18	$3.1	11.5%	27
Indianapolis Power & Light Company	37.45	34.22	3.23	$2.4	8.6%	28
Columbus Southern Power Company	39.22	36.53	2.69	$2.0	6.9%	29

Source: Testimony and Exhibit of Maurice Brubaker (R-943721), Exhibit MEB-1 and MEB-2.

EXHIBIT R6
MODIFIED DEFICIENCY ASSIGNMENT METHODS FOR PP&L

	PP&L PROPOSAL			$50 MILLION DEFICIENCY Class Deficiency Assignment			NEGATIVE $50 MILLION DEFICIENCY Class Deficiency Assignment		
Class	Present Revenues	Proposed Revenues	Deficiency	Proportional Scaleback	Constant Differential	Weighted Scaleback	Proportional Scaleback	Constant Differential	Adj. Wtd. Scaleback
RS	887.1	1,022.7	135.6	26.3	51.1	32.5	NM	10.5	(8.2)
RTS	19.8	23.2	3.4	0.7	1.6	0.9	NM	0.6	(0.0)
GS-1	162.2	168.5	6.3	1.2	(9.2)	(1.4)	NM	(16.6)	(8.8)
GS-3	507.2	541.3	34.1	6.6	(14.2)	1.4	NM	(37.5)	(21.8)
LP-4	273.4	301.1	27.8	5.4	1.7	4.5	NM	(10.8)	(8.1)
LP-5	259.6	299.7	40.1	7.8	15.4	9.7	NM	3.5	(2.2)
LPEP	8.4	8.9	0.5	0.1	(0.3)	(0.0)	NM	(0.7)	(0.4)
SL/AL	21.2	24.2	3.0	0.6	1.0	0.7	NM	0.0	(0.3)
GH(R)	43.6	50.7	7.0	1.4	2.9	1.7	NM	0.9	(0.3)
Sub-Total	2,182.4	2,440.3	257.9	50.0	50.0	50.0	NM	(50.0)	(50.0)
ISA	20.4	20.5	0.0	0.0	0.0	0.0	NM	0.0	0.0
Standby	1.1	1.2	0.0	0.0	0.0	0.0	NM	0.0	0.0
Stystem	2,204.0	2,462.0	257.9	50.0	50.0	50.0	NM	(50.0)	(50.0)
				Percent Change in Rates			*Percent Change in Rates*		
RS	887.1	1,022.7	15.3%	3.0%	5.8%	3.7%	NM	1.2%	-0.9%
RTS	19.8	23.2	17.4%	3.4%	7.9%	4.5%	NM	3.3%	-0.1%
GS-1	162.2	168.5	3.9%	0.8%	-5.6%	-0.8%	NM	-10.2%	-5.4%
GS-3	507.2	541.3	6.7%	1.3%	-2.8%	0.3%	NM	-7.4%	-4.3%
LP-4	273.4	301.1	10.2%	2.0%	0.6%	1.6%	NM	-3.9%	-2.9%
LP-5	259.6	299.7	15.4%	3.0%	5.9%	3.7%	NM	1.3%	-0.9%
LPEP	8.4	8.9	5.5%	1.1%	-4.0%	-0.2%	NM	-8.6%	-4.8%
SL/AL	21.2	24.2	14.3%	2.8%	4.8%	3.3%	NM	0.2%	-1.3%
GH(R)	43.6	50.7	16.1%	3.1%	6.6%	4.0%	NM	2.0%	-0.6%
Sub-Total	2,182.4	2,440.3	11.8%	2.3%	2.3%	2.3%	NM	-2.3%	-2.3%
ISA	20.4	20.5	0.2%	0.2%	0.2%	0.2%	NM	0.2%	0.2%
Standby	1.1	1.2	0.7%	0.7%	0.7%	0.7%	NM	0.7%	0.7%
Stystem	2,204.0	2,462.0	11.7%	2.3%	2.3%	2.3%	NM	-2.3%	-2.3%

Notes:

1) Proportional Scaleback: Original class deficiency is reduced by the percentage decline in the overall deficiency.
2) Constant Differential: PP&L class proposed percent increase in rates is reduced by the differential between the PP&L system percent increase and the revised system increase.
3) Weighted Scaleback: w * (proportional scaleback deficiency) + (1-w)*(constant differential deficiency), where w = (1-revised deficiency)/(original deficiency): w <= 75%.
4) ISA and Standby classes are assumed to exhibit no change in the proposed deficiency.
5) Adjusted Weighted Scaleback: Weighted scaleback deficiency result adjusted downward using constant differential method.

EXHIBIT R7

Company's Response to OSBA-28

and

Excerpt from Dr. Johnson's Workpapers Relating to OCA Stmt. 3

Pennsylvania Power & Light Company
Response to Interrogatories of
the Office of Small Business Advocate
Dated February 17, 1995
Docket No. R-00943271

Q. 28. The OSBA observes that in its minimum size distribution classification approach that PP&L uses the minimum size equipment currently being installed. With respect to that assumption:

a. Please provide all your reasons for using this approach.

b. for each category of distribution equipment, please define the size and nature of the actual minimum size equipment currently on the system, and the ratio of embedded costs for actual minimum size equipment to current minimum size equipment.

c. For each category of distribution equipment, please define the share of embedded costs that is accounted for by plant that is less than the current minimum size.

A. 28. a. The classification of PP&L's distribution plant into its demand and customer components is based on the Minimum Size Method described in the NARUC Cost Allocation Manual, published in January 1992. The NARUC manual recommends using the minimum size equipment (pole, conductor, cable, transformer, and service) that currently is being installed on a utility's system.

b. The following table reflects the minimum size equipment that exists on PP&L's system and the ratio of the embedded cost of that equipment to the minimum size equipment currently being installed. For services in Account 369, the current minimum size equipment being installed and the existing minimum size equipment are the same.

Account	Description	Embedded Cost of Existing Minimum Size Equipment	Ratio to Minimum Size Currently Being Installed
364	10 Foot Wood Pole	$67	0
365	4 & Below 1/C Overhead Conductor	353,033	.0036
367	4 & Below 1/C Underground Conductor	259	0
368.2	1 KVA Overhead Transformer	984,316	.0399
368.4	5 KVA Pad Mount Transformer	121,584	.0131

c. The following table reflects the proportionate share by account of the embedded cost of existing equipment that is smaller in size than the minimum size equipment currently being installed on PP&L's system. For services in Account 369, the minimum size currently being installed is the only size service.

Account	Embedded Cost of Plant Smaller Than Current Minimum Size Plant	Percent of Account Total
364	$76,851,188	12.86%
365	353,033	0.08
376	259	0.00
368.2	2,747,230	2.52
368.4	472,852	1.04

OCA STATEMENT NO. 3

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)))	DOCKET NO. R-00943271

WORKPAPERS

OF

DR. CHARLES E. JOHNSON

ON CLASS COST OF SERVICE AND RATE DESIGN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

APRIL 1995

EXETER

Associates, Inc.

12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

PENNSYLVANIA POWER & LIGHT COMPANY
TEST YEAR ENDED 9/30/95 OCA STUDY

ADJUSTED MINIMUM SYSTEM

	Allocator	Jurisdiction	RS	R1S	GS-1	GS-3	LP-4	LP-5	LPEP	ISA	GH	SL/AL	STANDBY
1 ELECTRIC PLANT IN SERVICE													
2 PRODUCTION PLANT													
3 NUCLEAR	D10	3,191,830	1,218,197	50,925	160,558	688,360	434,472	505,297	13,735	46,384	63,744	8,871	1,337
4 WHOLLY-OWNED COAL	D10	1,215,004	463,720	19,385	61,118	262,032	165,387	192,347	5,228	17,656	24,265	3,358	509
5 OTHER NON-NUCLEAR	D10	614,606	234,571	9,806	30,916	132,548	83,660	97,298	2,645	8,931	12,274	1,699	257
6 TOTAL PRODUCTION PLANT		5,021,440	1,916,488	80,116	252,592	1,082,940	683,519	794,941	21,608	72,972	100,283	13,877	2,104
7 TRANSMISSION PLANT													
8 500/230 KV	D10	284,126	108,440	4,533	14,292	61,276	38,675	44,980	1,223	4,129	5,674	785	119
9 138/69 KV	D16	81,481	31,695	1,325	4,177	17,910	11,304	13,147	0	0	1,658	230	35
10 TOTAL TRANSMISSION PLANT		365,607	140,135	5,858	18,470	79,185	49,979	58,127	1,223	4,129	7,333	1,015	154
11 DISTRIBUTION PLANT													
12 SUBSTATIONS													
13 GENERATION STEP-UP	D10	6,194	2,364	99	312	1,336	843	981	27	90	124	17	3
14 138/69 KV	D10	72,867	27,811	1,163	3,665	15,715	9,919	11,536	314	1,059	1,455	201	31
15 PRIMARY	D20	254,924	118,300	4,945	15,592	66,847	42,192	0	0	0	6,190	857	0
16 SECONDARY	D31	5,392	3,067	239	420	1,436	0	0	0	0	206	24	0
17 TOTAL SUBSTATIONS		339,377	151,542	6,446	19,989	85,334	52,954	12,516	340	1,149	7,975	1,099	33
18 OVERHEAD LINES													
19 138/69 KV	D10	293,713	112,099	4,686	14,775	63,343	39,980	46,498	1,264	4,268	5,866	812	123
20 PRIMARY	D20	252,467	117,160	4,898	15,442	66,203	41,785	0	0	0	6,131	848	0
21 SECONDARY													
22 DEMAND COMPONENT	D30	280,628	0	29,906	2,329	215,164	0	0	0	0	29,935	3,294	0
23 CUSTOMER COMPONENT	C30	345,237	300,112	4,092	34,159	5,331	0	0	0	0	1,258	284	0
24 STREET LIGHTING	K405	31,788	0	0	0	0	0	0	0	0	0	31,788	0
25 TOTAL OVERHEAD LINES		1,203,833	529,371	43,582	66,704	350,041	81,766	46,498	1,264	4,268	43,190	37,026	123
26 UNDERGROUND LINES													
27 138/69 KV	D10	9,992	3,814	159	503	2,155	1,360	1,582	43	145	200	28	4
28 PRIMARY	D20	35,829	16,627	695	2,191	9,395	5,930	0	0	0	870	120	0
29 SECONDARY													
30 DEMAND COMPONENT	D30	81,697	0	8,706	678	62,639	0	0	0	0	8,715	959	0
31 CUSTOMER COMPONENT	C30	136,336	118,518	1,616	13,490	2,105	0	0	0	0	497	112	0
32 TOTAL UNDERGROUND LINES		263,854	138,958	11,177	16,862	76,294	7,290	1,582	43	145	10,281	1,219	4
33 LINE TRANSFORMERS													
34 DEMAND COMPONENT	D30	128,470	0	13,691	1,066	98,501	0	0	0	0	13,704	1,508	0
35 CUSTOMER COMPONENT	CW8	166,524	121,938	1,656	18,684	5,553	0	0	0	0	934	17,758	0
36 TOTAL LINE TRANSFORMERS		294,994	121,938	15,347	19,750	104,054	0	0	0	0	14,638	19,266	0
37 SERVICES													
38 DEMAND COMPONENT	D30	25,029	0	2,667	208	19,190	0	0	0	0	2,670	294	0
39 CUSTOMER COMPONENT	CW9	270,128	205,270	2,793	25,714	5,231	0	0	0	0	1,058	30,062	0
40 TOTAL SERVICES		295,157	205,270	5,460	25,922	24,421	0	0	0	0	3,728	30,356	0
41 METERS	CW1	83,000	39,574	3,057	13,650	16,002	3,609	2,594	168	316	4,029	0	0
42 AREA LIGHTING FIXTURES	K403	3,897	0	0	0	0	0	0	0	0	0	3,897	0
43 STREET LIGHTING	K405	48,886	0	0	0	0	0	0	0	0	0	48,886	0
44 TOTAL DISTRIBUTION PLANT		2,532,998	1,186,652	85,068	162,876	656,147	145,619	63,190	1,815	5,878	83,842	141,750	160
45 DEMAND COMPONENT													
46 CUSTOMER COMPONENT													
47 TOTAL GENERAL PLANT	K433	257,726	127,259	4,268	16,237	45,277	25,719	27,818	761	2,548	4,574	3,191	74
48 DEMAND COMPONENT													
49 CUSTOMER COMPONENT													
50 TOTAL INTANGIBLE PLANT	K433	18,935	9,350	314	1,193	3,327	1,890	2,044	56	187	336	234	5
51 DEMAND COMPONENT													
52 CUSTOMER COMPONENT													
53 TOTAL ELECTRIC PLANT IN SVC		8,196,706	3,379,884	175,624	451,367	1,866,876	906,726	946,119	25,462	85,714	196,368	160,068	2,497
54 IL CAPACITY VALUE EFFECT		0	7,372	351	969	4,414	136	(10,728)	84	(3,104)	462	36	8
55 TOTAL ADJUSTED ELECTRIC PLT		8,196,706	3,387,256	175,975	452,336	1,871,290	906,862	935,391	25,546	82,610	196,830	160,104	2,505

PENNSYLVANIA POWER & LIGHT COMPANY
TEST YEAR ENDED 9/30/95 OCA STUDY

		Allocator	Jurisdiction	RS	RTS	GS-1	GS-3	LP-4	LP-5	LPEP	ISA	GH	SL/AL	STANDBY
1	I CUSTOMERS, WEIGHTED													
2	A-EXPRESSED IN $1,000													
3	METER INVESTMENT		82,998	0	0	0	0	0	0	0	0	0	0	0
4	METER READING EXPENSE		9,373	0	0	0	0	0	0	0	0	0	0	0
5	LATE PAYMENTS		6,763	0	0	0	0	0	0	0	0	0	0	0
6	UNCOLLECTIBLE ACCOUNTS		10,628	0	0	0	0	0	0	0	0	0	0	0
7	CUSTOMER DEPOSITS		1,065	0	0	0	0	0	0	0	0	0	0	0
8	CUSTOMER ADVANCES		39,911	0	0	0	0	0	0	0	0	0	0	0
9	B-EXPRESSED IN UNITS													
10	LINE TRANSFORMERS, CUST COMP		1,475,214	0	0	0	0	0	0	0	0	0	0	0
11	SERVICES CUSTOMER COMPONENT		1,413,615	0	0	0	0	0	0	0	0	0	0	0
12														
13	II CUSTOMERS (UNITS)													
14	TOTAL CUSTOMERS		1,228,047	1,066,688	14,544	121,411	18,948	843	119	1	1	4,473	1,010	9
15	FERC SYSTEM CUSTOMERS		0	0	0	0	0	0	0	0	0	0	0	0
16	SECONDARY CUSTOMERS		1,227,074	1,066,688	14,544	121,411	18,948	0	0	0	0	4,473	1,010	0
17														
18	III DEMANDS (KW)													
19	GENERATION LEVEL DEMANDS		5,325,423	0	0	0	0	0	0	0	0	0	0	0
20	69 KV LEVEL DEMANDS		5,235,871	0	0	0	0	0	0	0	0	0	0	0
21	PRIMARY LEVEL DEMANDS		4,465,951	0	0	0	0	0	0	0	0	0	0	0
22	CLASS MAXIMUM DEMANDS FTY		5,971,000	0	0	0	0	0	0	0	0	0	0	0
23														
24	IV ENERGY (1,000 KWH)													
25	GENERATION LEVEL ENERGY		33,464,555	0	0	0	0	0	0	0	0	0	0	0
26	SALES LEVEL MWH SALES		31,406,086	0	0	0	0	0	0	0	0	0	0	0
27														
28	V. DIRECT ASSIGNMENT													
29	AREA LIGHTS		1	0	0	0	0	0	0	0	0	0	0	0
30	STREETLIGHTS		1	0	0	0	0	0	0	0	0	0	0	0
31														
32	VI AMOUNTS EXPRESSED IN $1,000													
33	RATE REVENUE PRESENT LEVEL		2,263,602	0	0	0	0	0	0	0	0	0	0	0
34	ENERGY REVENUE PRESENT LEV		(21,487)	0	0	0	0	0	0	0	0	0	0	0
35	STATE TAX ADJ SURCHARGE		0	0	0	0	0	0	0	0	0	0	0	0
36	SPEC BASE RATE CREDIT ADJ		(38,084)	0	0	0	0	0	0	0	0	0	0	0
37	ANNUALIZATION REVENUES		25,615	0	0	0	0	0	0	0	0	0	0	0
38	ANNUALIZATION		28,629	0	0	0	0	0	0	0	0	0	0	0

OCA STATEMENT NO. 3A

5/25/95
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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)	DOCKET NO. R-00943271

REBUTTAL TESTIMONY

OF

DR. CHARLES E. JOHNSON

ON CLASS COST OF SERVICE AND RATE DESIGN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 1995

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)	DOCKET NO. R-00943271

REBUTTAL TESTIMONY
OF
DR. CHARLES E. JOHNSON

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Charles E. Johnson. I am a Principal with Exeter Associates, Inc. Our offices are located at 12510 Prosperity Drive, Silver Spring, Maryland, 20904.

Q. ARE YOU THE SAME CHARLES E. JOHNSON WHO HAS PREVIOUSLY FILED TESTIMONY ON RATE DESIGN AND CLASS COST OF SERVICE IN THIS PROCEEDING?

A. Yes.

II. PURPOSE AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. In my rebuttal testimony on Class Cost of Service and Rate Design, I will respond to certain statements made by PP&L Industrial Customer Alliance (PPLICA) Witness Baron, Bethlehem Steel Corporation Witness Maurice Brubaker, Office of Small Business Advocate (OSBA) Witness Knecht, University/College Coalition Witness Eisdorfer and Office of Trial Staff (OTS) Witness Yarolin.

PPLICA Witness Baron

Q. WHAT ISSUES RAISED BY MR. BARON WILL YOU ADDRESS?

A. I will address the following issues raised by Mr. Baron.

- Allocation of EDI/IDI Credits on Rate Base.
- Treatment of Interruptible Credits.

Q. HOW HAS MR. BARON ALLOCATED THE EDI/IDI CREDITS IN HIS COST OF SERVICE STUDY?

A. Mr. Baron has used rate base to allocate the EDI/IDI credits. This is a particularly inappropriate method for allocating these credits. There is a question as to whether or not the amount of credits given by the Company to industrial customers are of sufficient benefit to all customers to recover the full cost of the credits provided from ratepayers and I have recommended in OCA Statement 5 that they not be. Even if they were determined to be of sufficient benefit so that all ratepayers should share in the recovery of these costs, there is absolutely nothing that ties any benefits received to the rate base allocated to each customer class. Any benefits that may be received by ratepayers have not been identified nor quantified by PP&L. While it is not inconceivable that some benefits may be identified that can be tied to rate base, no attempt has been made to do so either by Mr. Baron or by the Company. To the extent that the are benefits of the EDI/IDI credits to ratepayers, they are more likely tied to the size of the customer's bill than to the amount of rate base allocated to that customer. In the absence of a specific basis on which to allocate these costs, the recommendation I made in my direct testimony to allocate the EDI/IDI credits on the basis of revenue is more appropriate than the use of rate base.

This difference in allocation of the EDI/IDI credits, combined with my proposal for a 50-50 sharing of these credits between shareholders and ratepayers would reduce the cost of service to the RS class by about $7.6 million from Mr. Baron's study.

Q. HOW DOES MR. BARON'S TREATMENT OF INTERRUPTIBLE CREDITS DIFFER FROM YOUR PROPOSAL?

A. Mr. Baron's treatment of interruptible credits is completely opposite to mine. Mr. Baron's approach is to insist on an allocated cost of service approach, in which interruptible rates are based on the costs allocated in the cost of service study, not relying on any market values in the setting of interruptible costs. The approach I have used in my cost study is to allocate to other ratepayers the cost level associated with the value to those other ratepayers of having interruptible customers on the system.

Mr. Baron believes that interruptible customers are entitled to cost-of-service based rates, and objects to PP&L's CT cost valuation and the valuation of a PJM capacity credit sale (used in my calculations). In his testimony, he states "Both of these approaches ... reflect a market based approach that is inherently discriminatory to interruptible customers who desire to purchase lower quality power." [Emphasis added.] [P. 66.]

The problem with his claim that interruptible rates should be based purely on cost of service is that he provides no basis for establishing the cost of serving interruptible customers. He does not calculate the cost of serving interruptible customers nor does he estimate the cost of serving interruptible customers. Mr. Baron arbitrarily decides that a maximum of 50 percent of the cost of production demand is a reasonable basis for the cost of serving interruptible customers. Mr. Baron asserts that he has relied on a discount of at least 50 percent off the production demand cost in previous

Pennsylvania cases, noting that this recognizes that interruptible loads are not included in PP&L resource plans and yet that some measure of fixed production demand costs may be assignable to interruptible customers. This is not an estimate of the production cost for interruptible customers. It is only recognition that something between zero and 100 percent of the normal production costs should be allocated to the interruptible class.

Q. HAS MR. BARON ALLOCATED HIS RECOMMENDED 50 PERCENT OF PRODUCTION COSTS TO INTERRUPTIBLE CUSTOMERS IN HIS COST STUDY?

A. No. After having expressed his strong support for cost-of-service based rates, Mr. Baron does not rely on his recommendation that 50 percent of production costs be allocated to interruptible customers. He simply chooses to rely on another measure of the value of the interruptible credits than that used by PP&L.

Additionally, the value he relied on in his cost study is the value of the credit to the interruptible customer, not the value of the interruptible load to the system or other ratepayers. This misconstrues the value of the resource approach used by the Company. According to this kind of thinking, any value that the Company might assign to the interruptible credit for any purpose (even if not cost based) is the appropriate value of the resource to be allocated to other ratepayers and recovered from them.

<u>Bethlehem Steel Corporation Witness Brubaker</u>

Q. WHAT ISSUES RAISED BY MR. BRUBAKER DO YOU INTEND TO ADDRESS?

A. Mr. Brubaker also raises the issue of competition in the electric utility industry and provides comparisons of costs of providing service to large industrial customers under

PP&L's tariffs compared with costs under tariffs of other specific utilities in the industrial Midwest. He also raises the same issues addressed by Mr. Baron about the class cost of service study, but his proposal is to allocate no production investment to interruptible customers. I will first address his proposed treatment of interruptible credits. As far as Mr. Brubaker's assertion that PP&L's industrial rates are high and non-competitive, I will point out four reasons his analysis is incomplete and I will provide a different perspective on competitive markets.

Q. WHY SHOULD INTERRUPTIBLE CUSTOMERS BE ASSIGNED ANY PORTION OF THE CAPACITY COST OF PRODUCTION INVESTMENT?

A. Interruptible customers make use of production facilities most hours of the year (PP&L's interruptible rider provides that interruptible customers will be interrupted no more than 200 hours per year.) The other 8,560 hours of the typical year, interruptible customers make relatively intensive use of PP&L's production plant. In my development of the peak and average cost allocation methodology for production investment, I showed that approximately 60 percent of the production investment was energy related. Allocation of the energy portion of production investment has nothing to do with interruptibility and these customers should be allocated whatever portion their energy consumption dictates.

At most, one might argue that interruptible customers should not be allocated 100 percent of the demand related component of production investment (i.e., the remaining 40 percent of production investment). However, if that were done, there would not also be an offsetting rate base adjustment for the value of the interruptibility. It would be one or the other. In my study, I have chosen to follow the approach developed by the Company in calculating a rate base offset.

Even Mr. Baron recognizes that "... some measure of fixed production demand costs may be assignable to these interruptible customers." [Page 70].

Q. PLEASE IDENTIFY THE FOUR REASONS MR. BRUBAKER'S ANALYSIS IS INCOMPLETE.

A. The four reasons Mr. Brubaker's analysis is incomplete are:

- A comparison of PP&L's <u>proposed</u> industrial tariffs with <u>existing</u> industrial tariffs of other companies is an inappropriate comparison.
- The comparison of firm tariffs does not reflect the actual prices paid by industrial customers for electric service from PP&L.
- Mr. Brubaker has omitted comparison of other neighboring states that have higher power costs.
- Mr. Brubaker's analysis focuses only on a comparison of industrial rates and not on the fact that PP&L is a relatively higher cost company than those selected by Mr. Brubaker.

Q. WHY IS IT INAPPROPRIATE TO COMPARE PP&L'S PROPOSED TARIFFS WITH CURRENT TARIFFS OF OTHER UTILITIES?

A. The OCA has proposed a reduction in PP&L's rates. The Office of Trial Staff has proposed no increase in firm or interruptible rates for industrial customers. The rates proposed by PP&L are not in effect, are subject to numerous challenges and are unlikely to become effective at the rate levels requested. Thus, a suggestion that costs under the proposed PP&L rates would be faced by PP&L industrial customers is inappropriate.

Q. WHY WOULD USE OF THE TARIFFED RATES FOR THESE COMPARISONS BE IMPROPER?

A. The use of the tariff for calculating costs to be compared across companies is improper because it does not reflect other factors that may be incorporated in the cost of service. For example, use of the tariff alone does not reflect any benefits from economic development credits or from any other features of PP&L's rates. A comparison under the tariff is only part of the picture, and not the full picture.

Q. IF UTILITIES FROM NEW YORK, NEW JERSEY AND MARYLAND WERE INCLUDED IN THIS COMPARISON, HOW WOULD PP&L FARE?

A. I have not calculated the cost of electricity for the various sized customers used by Mr. Brubaker in his exhibits, but can make a comparison of the total revenue per kilowatthour for industrial customers in these states. I have reviewed the Edison Electric Institute Typical Electric Bills for Winter 1994 for Pennsylvania, New Jersey, New York and Maryland. This review shows that every single New Jersey electric utility receives a higher revenue per kilowatthour from industrial customers than does PP&L. For New York, revenues per kilowatthour from industrial customers is lower than for PP&L for only one utility, Niagara Mohawk Power Company, out of the seven utilities listed, and that is lower by only approximately 3 mils per kilowatt-hour. Two of the five Maryland utilities listed have higher revenues per kilowatt-hour from industrial customers than PP&L and three of the companies have lower revenues per kilowatthour. Thus of the 16 utilities in these three neighboring states, only four have lower revenues per kilowatthour from industrial customers than does PP&L. These utilities are listed with the industrial revenue per kWh in Exhibit ___ (CEJ-3), Schedule 1. Inclusion of utilities from these states in Mr. Brubaker's exhibits would likely produce results that would have shown PP&L to be more in the middle of costs for electric power for industrial customers.

Q. OF THE COMPANIES CONTAINED IN MR. BRUBAKER'S EXHIBITS, IS PP&L A HIGHER COST COMPANY?

A. Yes. I have used the Edison Electric Institute Typical Electric Bills for Winter 1994 to look at the average revenue per kilowatthour for each of those utilities. These utilities are listed with the overall revenue per kWh in Exhibit ___ (CEJ-3), Schedule 2. Of the 32 utilities in his list, Pennsylvania Power and Light Company was ninth highest in overall revenue per kilowatthour. For it to have shown up seventh or eighth highest in cost for varying sizes and load factors of customers under the standard tariffs is not surprising. However, for a higher cost company relative to those in Mr. Brubaker's list, it is surprising that it is the fifteenth highest cost company for interruptible load in the list of utilities provided by Mr. Brubaker.

Office of Small Business Advocate Witness Knecht

Q. WHAT ISSUES RAISED BY MR. KNECHT WILL YOU ADDRESS?

A. I will address only one issue raised by Mr. Knecht, and that is his proposal for an automatic annual adjustment in rates in each of the next ten years.

Q. PLEASE DESCRIBE THE ANNUAL ADJUSTMENT PROPOSED BY MR. KNECHT.

A. Mr. Knecht proposes to reduce the energy charge in the GS-1 tariff by 2 mils each year and to increase the energy charge for rate schedules RS, RTS, and GH classes by about .24 mils per kWh each year. Mr. Knecht has singled out these three classes on the basis that they "are substantially under-contributing at the proposed rates." He has based selection of these classes entirely on the Company's class cost-of-service study, the Company's proposed revenue request and the Company's distribution of the increase in revenues. Even relying on those Company proposals, he has excluded the classes with the second and third lowest rates of return under Company proposals, namely Interruptible Service by Agreement (ISA) and Street and Area Lighting (SL/AL) classes. He characterizes his reason for exclusion of the SL/AL classes from the adjustment on the basis of simplicity, but is unclear about what is being simplified. He makes no mention of the fact that the class with the second lowest rate of return under the Company's study, ISA, is excluded entirely from his proposal.

Q. IF MR. KNECHT'S PROPOSED INCREASED WERE SPREAD OVER ALL THE CLASSES WITH BELOW AVERAGE RATES OF RETURN, WOULD THAT BE ACCEPTABLE?

A. No, of course not. This proposal for an automatic adjustment to rates in each of the next ten years based on the Company's class-cost-of-service study is outside the realm of acceptable ratemaking. It is not just that the Company's class cost-of-service study is flawed, but that no study done today can be expected to represent the allocation of costs accurately over the next ten years. Usage levels change, usage patterns change and other factors affecting cost allocations change. There is no reason to believe that the relative class rates of return reflected in a study performed today would still be valid in ten years. In addition, the OCA study more accurately reflects the cost of serving the residential class than does the PP&L study and the OCA study does not show the residential class with a below average rate of return. Increasing the residential energy charge every year for ten years would improperly increase their rates to well above average.

Q. IS THE RATE OF RETURN FOR THE GS-1 CLASS HIGHER THAN FOR ANY OTHER CLASS?

A. No. Under both my study and the Company's study, the rate of return for the standby class is higher than for the GS-1 class. However, under either study, the rate of return for the GS-1 class is well above average. Both the Company and I have proposed substantially below average increases for the GS-1 class and if the Commission orders a rate reduction as recommended by the OCA, I have recommended that the largest reduction be given to the GS-1 class. Actions of this sort are more appropriately taken in the context of a general rate case and based on a current cost-of-service study for the customer classes.

<u>University/College Coalition Witness Eisdorfer</u>

Q. WHAT ISSUE RAISED BY MR. EISDORFER WILL YOU ADDRESS?

A. I will address Mr. Eisdorfer's proposed rate increases to rate schedules RS and RTS, which are excessive. His proposal rests on the use of a cost study in which all production investment is allocated on the basis of winter peak demands, which I have shown in my direct testimony to be inappropriate.

His proposal also fails to meet the commonly-used objective of gradualism in changing rates. Mr. Eisdorfer's proposed 35.1 percent increase in RTS rates is over three times the system average increase of 11.7 percent requested by PP&L. This fails to meet the test of gradualism. His proposal to increase rates for rate schedule RS by 25.5 percent also exceeds the level that is reasonable and should not be adopted by the Commission. Because his method is mechanistic and cannot accommodate such ratemaking principles as gradualism, it should be rejected by the Commission.

<u>Office of Trial Staff Witness Yarolin</u>

Q. WHAT ISSUES RAISED BY OTS WITNESS YAROLIN WILL YOU ADDRESS?

A. I will address Mr. Yarolin's proposal to raise the rates for residential thermal storage (RTS) customers by over 17 percent and the residential customer charge by 23 percent, while leaving revenue levels for all other classes at current levels.

Q. PLEASE DESCRIBE MR. YAROLIN'S RECOMMENDATIONS?

A. Mr. Yarolin recommends that the Commission adopt the Company's proposed increases for the RTS rate class and that the residential rate schedule RS customer charge be increased from $4.80 per month to $5.90 per month. According to Mr. Yarolin, the revenue increases from these two recommendations equals approximately $17.4 million, the amount of revenue increase from PP&L recommended by OTS. If the Commission awards PP&L a higher revenue level than recommended by OTS, Mr. Yarolin proposes that the additional revenues be recovered from rate classes (excluding RTS) in proportion to the Company's proposal. Mr. Yarolin also proposes that the Commission institute an investigation regarding the RTS rate.

Q. WHAT IS MR. YAROLIN'S REASON FOR PROPOSING A COMMISSION INVESTIGATION ABOUT RTS SERVICE?

A. Mr. Yarolin expresses his concern that some of these customers may have been induced to commit to the service with overly optimistic promises of lower rates when compared to Rate Schedule RS. Mr. Yarolin also notes, among other reasons, that these customers made a sizable investment in equipment in order to take advantage of the RTS rate. Given that he has these concerns, I think it is important that the RTS rate not be increased by as large a percentage as that proposed by the Company or OTS. As I noted in my direct testimony, the differential between the RTS rate and the traditional electric heating rate which induced these customers to purchase the thermal storage system should be maintained by giving the two classes approximately the same percentage increase.

Q. ON WHAT COST BASIS HAS MR. YAROLIN RELIED FOR HIS RECOMMENDATIONS?

A. Mr. Yarolin has relied on the Company's class cost-of-service study and related analyses for his recommendation, and he has compared PP&L's residential customer charge with those of other Pennsylvania utilities. In his comparison, he found that the OTS-proposed RS customer charge is in the range of other Pennsylvania utility residential customer charges. That is also true of the current PP&L RS customer charge and the customer charge proposed by PP&L. Thus a comparison of these customer charges provides no cost basis for setting the RS customer charge.

Because he has relied on the Company's cost analyses, he has relied on a customer cost analysis that is flawed, as I addressed in my direct testimony on cost of service and rate design. Reliance on the Company's cost-of-service study also suffers from the same problem, i.e., the Company's study possesses flaws I describe in earlier testimony, particularly the cost allocation to the RTS class that over-allocates production capacity costs to RTS customers. The Company's flawed analysis should not serve as the basis for setting RS or RTS rates.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)	DOCKET NO. R-00943271

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY

OF

DR. CHARLES E. JOHNSON

ON CLASS COST OF SERVICE AND RATE DESIGN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 1995

PENNSYLVANIA POWER & LIGHT COMPANY

Revenue Per KWH From Industrial Customers

COMPANY	Cents per kWh
Duquesne Light Company	6.67
Metropolitan Edison Company	5.68
Pennsylvania Electric Company	5.25
Pennsylvania Power & Light Company - Present	**5.76**
Pennsylvania Power Company	5.10
Philadelphia Electric Company	5.25
Pike County Light & Power Company	7.44
UGI Corporation	6.11
West Penn Power Company	4.35
AVERAGE PENNSYLVANIA	6.24
Atlantic City Electric Company	8.13
Jersey Central Power & Light Company	8.80
Public Service Electric & Gas Company	7.79
Rockland Electric Company	9.50
AVERAGE NEW JERSEY	8.20
Central Hudson Gas & Electric Company	5.83
Consolidated Edison	12.38
Long Island Lighting Company	12.35
New York State Electric & Gas Company	7.74
Niagara-Mohawk Power Company	5.44
Orange & Rockland Utilities	8.31
Rochester Gas & Electric Company	7.78
AVERAGE NEW YORK	7.72
Baltimore Gas & Electric Company	5.19
Conowingo Power Company	7.58
Delmarva Power & Light Company	5.83
Potomac Electric Power Company	5.37
Potomac Edison Company	3.03
AVERAGE MARYLAND	4.68

SOURCE: Typical Electric Bills, Winter 1994, Edison Electric Institute

PAPUC Docket No. R-00943271
OCA Statement 3A
Exhibit___(CEJ-3)
Schedule 2

PENNSYLVANIA POWER & LIGHT COMPANY

Revenue Per KWH From All Customers

	Cents per kWh	Ranking
Toledo Edison Company	8.73	3
Philadelphia Electric Company	9.9	2
Cleveland Electric Illuminating Company	8.56	5
Ohio Edison Company	8.58	4
Detroit Edison Company	8.09	7
Duquesne Light Company	10.22	1
Northern Indiana Public Service Company	6.44	15
Pennsylvania Power & Light Company - Present	**7.37**	**9**
Pennsylvania Power Company	7.41	8
Commonwealth Edison Company	8.4	6
Illinois Power Company	6.82	12
Metropolitan Edison Company	6.88	10
Consumers Power Company	6.46	14
Central Illinois Public Service Company	6.55	13
Minnesota Power & Light Company	4.17	31
Pennsylvania Electric Company	6.82	11
Dayton Power and Light Company	6.39	16
Central Illinois Light Company	5.63	21
Cincinnati Gas & Electric Company	6.06	18
Indiana Michigan Power Company -IN	5.17	27
Northern States Power Company - WI	5.82	19
Union Electric Company - IL	4.63	29
West Penn Power Company	5.33	25
Wisconsin Public Service Corporation	5.37	24
Northern States Power Company - MN	5.62	22
Wisconsin Electric Power Company	5.66	20
Columbus Southern Power Company	6.18	17
Wisconsin Power & Light Company	5.24	26
Ohio Power Company	4.16	32
Indianapolis Power & Light Company	4.95	28
Indiana Michigan Power Company - MI	5.41	23
Public Service Company of Indiana	4.58	30

SOURCE: Typical Electric Bills, Winter 1994, Edison Electric Institute

OCA STATEMENT NO 3B

5/25/95

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DOCKETED

MAY 31 1995

PENNSYLVANIA POWER & LIGHT COMPANY	)	DOCKET NO. R-00943271

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SURREBUTTAL TESTIMONY

OF

DR. CHARLES E. JOHNSON

ON

CLASS COST OF SERVICE AND RATE DESIGN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 1995

DOCUMENT FOLDER

EXETER
Associates, Inc.
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

BA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)))	DOCKET NO. R-00943271

SURREBUTTAL TESTIMONY
OF
DR. CHARLES E. JOHNSON
ON
CLASS COST OF SERVICE AND RATE DESIGN

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Charles E. Johnson. I am a Principal with Exeter Associates, Inc. Our offices are located at 12510 Prosperity Drive, Silver Spring, Maryland, 20904.

Q. ARE YOU THE SAME CHARLES E. JOHNSON WHO HAS PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. PURPOSE AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY ON CLASS COST OF SERVICE AND RATE DESIGN?

A. I will respond to certain statements made by Pennsylvania Power and Light Company (PP&L) witnesses Kleha and Kasper, Office of Small Business (OSBA) witness Knecht, PP&L Industrial Customer Alliance (PPLICA) witness Baron and Bethlehem Steel Corporation witness Brubaker on the proper allocation of costs to PP&L rate classes, the appropriate spread of any revenue increase or decrease and rate designs for the residential service (RS) and residential thermal storage (RTS) classes.

Q. HOW ARE YOUR RESPONSES TO THOSE WITNESSES ORGANIZED?

A. Because several of these witnesses address the same issue and make the same or similar arguments, I will respond to each argument and identify the parties who have made such arguments. In general, I will not specifically address every statement made by every party.

III. MINIMUM DISTRIBUTION SYSTEM

Q. WHICH PARTIES ADDRESSED YOUR ADJUSTMENT TO PP&L'S COST STUDY TO ACCOUNT FOR THE LOAD-CARRYING CAPABILITY OF THE MINIMUM DISTRIBUTION SYSTEM?

A. Mr. Kleha and Mr. Knecht addressed my adjustment to account for the load-carrying capability of the minimum distribution system. Mr. Kleha lists four reasons he asserts that the allocator for the demand portion of the distribution system should not be adjusted to account for the load-carrying capability of the minimum system. Mr. Knecht objects to the results, which he characterizes as unreasonable, but offers no valid reasons why the adjustment is improper.

Q. PLEASE RESPOND TO THE FOUR REASONS MR. KLEHA CLAIMS THE PROPOSAL TO ADJUST THE DEMAND ALLOCATOR IS FLAWED.

A. (1) Mr. Kleha's first reason is that the minimum size distribution system must have some load-carrying capability and that is no reason to reject the minimum system approach. However, it is because the minimum size distribution system has load-carrying capability that it is not totally customer related, but is partially demand related. In fact, as I have shown, the minimum distribution system posited by Mr. Kleha can carry a substantial amount of distribution load. Because the investment in the minimum size distribution system is allocated on number of customers, the amount of capacity costs being allocated to the classes is not related to the class demands, but rather to the number of customers in the class. It is only appropriate to reflect the load-carrying capacity of the minimum size components by adjusting the demands in the allocator used for allocating the remaining (demand-related) portion of the distribution system.

(2) Mr. Kleha's second reason is that the demand allocators are derived from class loads and are "unaffected" by the minimum size distribution system study. Allocators are modified and adjusted throughout his cost study for numerous reasons. It does not follow that demands should not be adjusted for this reason. I have given ample justification in my direct testimony for adjusting the demand allocator for distribution demand.

(3) Mr. Kleha's third reason is that I have elected to adjust the Company's cost study rather than devise a completely different method of allocating distribution costs. His assertion that my proposed adjustment is arbitrary and incomplete is without foundation. My reasoning has been explained thoroughly in my direct testimony at pages 15-17.

(4) Mr. Kleha's fourth reason is his assertion that the primary-voltage system "undoubtedly" has a customer-related component that <u>could</u> offset his overstatement of customer-related costs of the secondary-voltage system. His unsupported and unquantified assertion that this might offset his overstatement should be contrasted with my quantification of the overstatement of customer-related costs and my class cost-of-service study incorporating that change. The Commission should accept my properly quantified and supported modifications.

Q. WHAT IS OSBA WITNESS KNECHT'S POSITION ON YOUR ADJUSTMENT TO PP&L'S MINIMUM DISTRIBUTION SYSTEM?

A. Mr. Knecht objects to the results of my adjustment and refers to it as "extreme." He then provides his explanation as to why he characterizes the results produced by my adjustment as extreme. First, the results are not extreme, but properly reflect cost causality and second, his purported explanation is incorrect.

Q. WHY DOES HE CHARACTERIZE YOUR RESULTS AS EXTREME?

A. Mr. Knecht seems to believe that allocation of distribution system should necessarily be done by a linear combination of the Company's customer allocator and its demand allocator and that nothing else is acceptable. There is no theoretical or empirical basis for such an approach. His reasoning has nothing to do with the relationship between the load-carrying capability of the minimum system and the classes' demand allocators and should be rejected.

Q. WHAT JUSTIFICATION FOR REJECTING YOUR ADJUSTMENT IS GIVEN BY MR. KNECHT?

A. Mr. Knecht discusses two general areas that he claims are methodological errors in my adjustment. First, he states that "It completely ignores the fact that some reserve capacity must be built into the system, to allow for demand growth, unexpected fluctuation in demand, etc." [Emphasis added] My response is in two parts. One, the minimum size distribution is intended by its adherents to account for providing a per customer cost of access to the electric system. Mr. Knecht's observation, however, relates entirely to capacity and demand. It is the demand that I am attempting to exorcise from the customer component by my adjustment, and for him to claim that I have ignored demand considerations is beside the point. Two, even if it were not beside the point, there is reserve capacity in the minimum distribution system. I credited each class with the nameplate rating of each transformer in making my adjustment, whereas PP&L will allow peak demands to exceed the nameplate rating by a substantial percentage before replacement with a larger transformer. For some transformers, loads can be up to 200 percent of the nameplate rating. This provides ample reserves.

In this part of his discussion, Mr. Knecht also notes that I have ignored the fact that distribution systems need to be built to meet non-coincident peak demands in each geographical area and not the diversified peak demands of the classes. Cost allocation of distribution systems is contentious partially because cost causality is difficult to ascribe. There are a great many factors that distribution planners take into account in planning distribution systems that are difficult to reflect in cost allocations. The need to develop the distribution system to meet peak demands in each geographical area is one such factor. No cost study submitted in this proceeding takes geographical peak demands into account. To the best of my recollection, I have never seen one that does. For Mr. Knecht to object to my study on these grounds is meritless.

The second methodological error in my study claimed by Mr. Knecht is that I made no effort to adjust for the demand effect built into the CW8 customer-component allocator for line transformers.

Q. WHAT IS THE CW8 ALLOCATOR?

A. The CW8 allocator is a weighted customer allocator used by PP&L in its cost study to allocate the customer-related portion of line transformers. There is no explicit use of demand in PP&L's development of the CW8 allocator.

In developing the CW8 allocator, the Company has combined the weighted numbers of customers served at two phase and three phase with actual numbers of single phase customers. Mr. Knecht's objection is somewhat off the mark in that he offers no suggestion as to what the demand effect might be or how to correct for it. However, if one assumed that the elimination of the weights would be necessary to adjust for the demand effect, the impact is minimal. While not conceding that the total elimination of the weightings is proper, such a change on the residential service class (the most affected by this change) would only be to increase the amount of net transformer investment by about $1.2 million. With a total amount of rate base of about $2,053 million, this would change rate base for the RS class by about 0.06 percent. The return and taxes on this additional rate base would be around $200,000, out of a total revenue of nearly $1,000,000,000 for the residential class. Any adjustment for the demand effect that might be built into the CW8 allocator would have a smaller effect than this.

IV. <u>PEAK AND AVERAGE COST ALLOCATION METHODOLOGY</u>

Q. Which statements will you address about your use of the Peak and Average cost allocation method?

A. I have identified eight incorrect assertions made by various parties that I will rebut and show to be erroneous.

Q. SEVERAL PARTIES CLAIM THAT FIXED COSTS ARE DEMAND-RELATED AND VARIABLE COSTS ARE ENERGY-RELATED. IS THIS CORRECT?

A. No. This general assertion has been made by PP&L witness Kleha and OSBA witness Knecht, although Mr. Knecht only refers to the classification as "common," and does not indicate whether he believes it to be correct. The argument is based on two incorrect notions; one, that the amount of investment in capacity is determined by peak demand; and two, that fixed costs should not be recovered through usage. As demonstrated in my direct testimony and as Company witnesses have observed, the peak demand on the system only determines the amount of capacity, not the mix and consequently, not the amount of investment in generating capacity that the utility must incur. The second incorrect notion is exemplified by Mr. Kleha's argument that a utility does not depreciate its plant on kWh, nor are property taxes tied to kWh generated. He asserts that fixed costs are tied to a utility's peak demands, as though the peak demands on a utility were fixed and unvarying and not subject to year-to-year fluctuations. However, peak demands vary just as the amount of energy generated does. It should be noted that the two examples mentioned by Mr. Kleha, depreciation and property taxes, do not change if the utility experiences an extraordinarily cold winter and has peak demands greatly exceeding expectations or if the region falls into an economic downturn and industrial customer loads are reduced. It should be clear that fixed costs are not inherently tied to either energy or demand. Fixed costs are fixed and both energy and demand can vary from year-to-year. The only way fixed costs could be recovered other than through usage (either energy or demand) would be to recover them through a customer charge.

Q. A SECOND CLAIM MADE IS THAT IF GENERATING CAPACITY INVESTMENT IS PARTIALLY ENERGY-RELATED, FUEL IS PARTIALLY DEMAND-RELATED. IS THAT TRUE?

A. No. This is referred to by Messrs. Brubaker, Kleha and Knecht, and is characterized as fuel symmetry, and is a red herring. There is no validity to the claims made by these parties that some portion of fuel should be allocated as being demand related in order for the peak and average method to be consistent.

The theoretical foundation is that for a perfectly-planned and perfectly-implemented utility generation system, the capital cost of meeting peak demand is determined by the cost of the least-cost generation, i.e., the investment in a combustion turbine peaking unit. This is because if the utility had no load to meet except for the peak hourly load, the lowest cost of meeting its requirements would be through construction of nothing but combustion turbine peaking units. Any additional costs of production (e.g., fuel) would be energy related.

If this ideal utility has to meet load during other than the peak hour, it would be able to do so at lower cost by constructing a mix of generating types; baseload coal and other types of generation, depending on that other load. The existence of this other load does not change the cost of meeting peak demand. It only changes the cost of meeting that additional load by reducing it from the higher fuel cost of the combustion turbine. If a utility has a relatively high load factor, it can meet its customers' requirements at lowest total cost by construction of substantial amounts of baseload capacity, because the fuel costs are lower than if the utility used only peaking units. It should be noted that the total costs of fuel and capital cost for the baseload unit (less the capital cost of the combustion turbine) are <u>less</u> than the fuel costs of a combustion turbine.

This concept is demonstrated in Exhibit___(CEJ-4), Schedule 1. This graph demonstrates the total costs (annual capital plus fuel) of production for a utility as a function of its mix of generating facilities. The scale on the X-axis is the percentage of generating capacity that is baseload, with the balance of the generating capacity being peaking plants. The Y-axis shows the total costs of meeting the utility requirements with the percentage of peaking units on the X-axis. The curve would be characterized as a U-shaped curve. It is high when the percentage of baseload plant is zero, falls as the percentage increases, reaches a low point and rises as the percentage of peakers diminishes to zero and all generating plant is baseload. The utility would choose the mix that produces total cost near the lowest point of the curve. This point would depend on the utility's load requirements. Generation planning is complex and there are other considerations, but this model captures much of the cost trade-offs in determining generation expansion plans for a utility.

This is also an appropriate point at which to point out that Mr. Baron has mischaracterized my application of the peak and average method as claiming that it assumes ". . . that the <u>entire</u> excess capital and fixed O&M costs of a baseload unit (e.g., the Susequehanna unit), over and above a fixed combustion turbine unit, are solely related to fuel savings." I made no such assumption. As far as the excess costs of Susquehanna are concerned, they are classified in the same 60/40 proportions that all production investment is. Mr. Baron is simply incorrect in stating that the uneconomic Susquehanna costs are assigned to customer classes on the basis of class energy. I have not allocated "mistakes" of the past on the basis of energy.

Q. HAVING CLARIFIED THE THEORY, PLEASE EXPLAIN WHY THERE IS NO DEMAND COMPONENT OF FUEL.

A. This can best be done by reference to Mr. Knecht's arguments, where he states "... it can equally well be argued that utilities expend substantially higher fuel costs for peaking units in order to save capital costs." Symmetry in his argument would first require that all capital costs be considered energy related and allocated on energy. Then a symmetric argument might be constructed. I have not done so, nor has any other party. What they have done is to have taken only one piece of a potential symmetric argument and attempt to include it with mine, but they do not first include the allocation on the basis of class energy of costs of capital for enough baseload capacity to meet system requirements.

Q. MR. BRUBAKER CLAIMS THAT HIGHER LOAD FACTOR CUSTOMERS PAY MORE PER KW OF GENERATING CAPACITY AND SHOULD RECEIVE A REDUCTION IN FUEL COSTS COMMENSURATE WITH THE HIGHER CAPITAL COST. IS HE CORRECT?

A. No. Mr. Brubaker's claim that customers receiving higher than average allocation of generating plant investment should receive a below-average fuel cost is based on his representation of generation plant net investment as being only peak demand related. In his table on page 6 of his rebuttal testimony he presents the net investment in generating plant <u>per kW</u> for three classes, RS, GS-1 and LP-5. These amounts were not derived in my study on a kilowatt basis, but as the result of the peak and average method, under which about 40 percent of the capacity costs were demand related. I have separated the net capacity investment into demand and energy portions on that basis, i.e., $246 of net plant per kW of demand, with the rest for each class being energy related. This separation is shown in Exhibit___(CEJ-4), Schedule 2.

Because the energy-related portion of net plant is stated on a per kW of peak demand,[1] the energy-related portion on a kWh basis can be obtained by dividing the values in column 4 of Exhibit___(CEJ-4), Schedule 1, by the kWh per kW for each class. The results of this calculation are shown in column 6 of Exhibit___(CEJ-4), Schedule 1, where each and every one is seen to have the same value, $.0661 of net plant per kWh.

What can be seen from this is that every class pays the same amount, $246, per kW of peak demand and the same amount, $.0661, per kWh of energy. Mr. Brubaker's demonstration conceals this, because he inappropriately calculates the net plant cost per kW of peak demand, which is not the appropriate basis for comparison. Peak demand is his preferred method of allocating generating capacity and any deviation only measures the difference from his preferred method.

An additional point should be made regarding Mr. Knecht's statement ". . . it can equally well be argued that utilities expend substantially higher fuel costs for <u>peaking units</u> in order to save capital costs." [Emphasis added] He has improperly extended this concept to claim that logic would require all fuel costs in excess of those for a baseload nuclear plant be classified as demand-related and allocated on peak demand. The logic of the peak and average method requires no such thing. The peak and average method is not premised on the basis that the fuel cost of a baseload coal plant is higher than the fuel cost of a nuclear plant because the utility expended more capital on the nuclear plant to obtain lower fuel costs. My analysis focused on the tradeoff between a coal plant and a combustion turbine. It was the calculation of this trade-off that resulted in determining that approximately 40 percent of generation capacity

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[1]For the five peak demands in the P&A study.

investment was demand related. Had I made the comparison to the Susquehanna nuclear units, the percentage of generation investment that was demand related would have been much smaller, less than 16 percent.

Q. IF THE OTHER PARTIES WERE CORRECT AND SOME PORTION OF THE HIGHER FUEL COST OF A COMBUSTION TURBINE WERE TO BE CONSIDERED DEMAND RELATED, WOULD THE IMPACT ON ALLOCATIONS BE LARGE?

A. No. The total amount of fuel for combustion turbines for the test year is only around $2 million out of a total fuel cost of about $450 million. Allocation of a portion of this on demand rather than energy would have little effect on the class rates of return. For example, allocation of the <u>entire</u> $2 million on demand rather than energy affects the residential class by less than $60,000 in expenses. Allocation of some portion would have an even smaller impact.

Q. DOES THE PEAK AND AVERAGE METHOD PROVIDE PERVERSE PRICE SIGNALS TO CUSTOMERS?

A. No. Mr. Baron has characterized the results of my method as perverse, and Messrs. Kleha and Knecht have also addressed the issue of price signals. There is a distinction between cost allocation and rate design that these analysts have forgotten. Price signals are in the realm of economic theory and are not identical to cost allocation. There are reasons that a utility may (rightly or wrongly) deviate from costs in setting prices. A utility may want to provide economic development incentives, independent of their cost. In a situation where capacity is short and cannot be bought at any price, the utility might well establish prices to inhibit increases in peak demand, where those prices are not based on allocated costs. I would generally agree that prices should reflect cost, but there often are other objectives in developing rates that need to be taken into account. These parties should not confuse rate design issues with cost allocation issues in an attempt to force the results of a cost study to fit specific rate design ideas. This is particularly true of Mr. Kleha's concern about the "sudden and very substantial increases in cost responsibility" for some customer classes. I have proposed limiting the impact of revenue increases on any one class, but have no objection to assigning cost responsibility where it belongs, even if it is a change from the past.

In that regard, Mr. Kleha is mistaken in his assertion that the method "would assign greater production cost responsibility to those customer classes who increase their load factors." If any customer class reduces it peak demand and increases its load factor, its cost responsibility falls. This is a simple consequence of the method. What Mr. Kleha may mean is that if any customer class increases its energy usage (even without increasing its peak demand), its cost responsibility will increase. This result should not be surprising -- if a customer buys more of what a utility is selling, one would expect its cost responsibility to increase. The only way this would not occur would be under a peak demand allocation. The increase in load factor is not the issue, the increase in consumption is and the peak and average method rightly imposes greater costs on customers who consume more.

Q. DOES THE PEAK AND AVERAGE METHOD OVERSIMPLIFY THE GENERATION PLANNING PROCESS?

A. No. Messrs. Baron and Brubaker make this assertion. Recall that both prefer[2] the single coincident peak demand for allocating production investment. Certainly generation planning is a complex process and incorporates extensive data, but it is inconsistent to assert that the peak and average method should be rejected because it oversimplified the planning process while advocating the use of the single peak

[2]Both accept the 12 CP method for PP&L, but believe the winter peak method is better.

demand of the Company. The single peak method is much simpler than the peak and average method.

Q. IS ENERGY BEYOND THE 2,531 HOUR "BREAKEVEN" POINT IRRELEVANT FOR COST ALLOCATION PURPOSES?

A. No. Mr. Baron performs what he characterizes as the breakeven point for PP&L embedded costs and asserts that the first 2,531 hours of the load duration curve are the only ones relevant to the economic choices facing PP&L. Mr. Brubaker makes a related claim.

This is merely another way to argue the fixed/variable issue with the fixed costs now related to the first 2,531 hours by Mr. Baron. The real issue here is the extent to which usage other than the single peak (or some other collection of peak) demand is responsible for capacity costs. Mr. Baron (and others) argue that the capacity costs are totally related to the classes' demands at the time of the system peak demand and that any additional usage of the generating capacity should be a free good, with no cost assigned to those who make use of the generating facilities at any other hour, paying only for fuel. Here, he has simply transferred that claim to the highest 2,531 hours of the load duration curve and asserts that is the basis for the peak and average method.

This is not the case. The purpose of generating capacity is to produce energy. It is built for that purpose and is operated for that purpose. Its costs are largely incurred in carrying out that purpose. There are other factors, of course, peak demand being the major one accounted for in the peak and average method, but energy is not free of cost except during the one hour of the year for which demand is greatest.

It may be the case the peak and average method does not capture all the nuances of generation planning and its cost causality as well as it might, but no other method mentioned in this proceeding even comes close to reflecting any of the generation planning complexities. Certainly the winter peak demand method favored by Messrs. Baron and Brubaker does not.

Q. IS ENERGY CONSUMPTION DOUBLE COUNTED IN THE PEAK AND AVERAGE METHOD?

A. No. Mr. Brubaker asserts that energy consumption (or average demand) is double counted in the peak and average method. Demand is the rate of consumption of energy. The peak demand of a utility is typically the highest average rate of consumption for any hour of the year. For customer billing purposes, many utilities use half-hourly demands or 15-minute demands. It could just as well be measured instantaneously, in which case, peak demands would not be related to any energy consumption, because in zero time, zero energy would be consumed. For practical reasons related to measuring demand, periods longer than instantaneous measurements are used.

By presenting a chart showing peak demands and average demands as he has, Mr. Brubaker mixed concepts that do not belong together. His claim is totally without merit.

Q. ARE THE FIVE PEAK DEMANDS INSUFFICIENT FOR MEASURING PEAK DEMAND?

A. Mr. Kleha, in his second, third and fourth reasons essentially argues that the five monthly peak demands I have used in my peak and average cost study are not sufficient to reflect various factors about the PP&L system. I have an open mind on this. I selected the five months with greatest demands based on the justification provided in my direct testimony, but there may be reasons that other months should be included in the peak and average study, even perhaps all 12 monthly peak demands. However, the five months I used reasonably reflect class peak demands that are important and the only peak and average study in the record uses these five. Even if additional monthly peaks would improve the results, my study should not be rejected because it does not include those additional peaks.

Q. IS PRECEDENT A JUSTIFICATION FOR REJECTING THE PEAK AND AVERAGE METHOD?

A. No. Mr. Kleha notes that the peak and average method proposed by the OCA was not adopted 13 years ago. Mr. Brubaker notes that the Public Utility Commission of Texas has not adopted any method relying on economic theory referred to as capital substitution. Other jurisdictions have. For example, Northern States Power Company in Minnesota uses a method that classifies a portion of each unit as energy related and Maine and Montana have both relied on marginal costs in determining class cost responsibilities. Under marginal cost approaches, marginal costs of production are classified as both energy and demand related, but the demand-related production costs do not equal the embedded cost of production plant.

Q. HOW MUCH EFFECT DOES EACH OF YOUR PROPOSED MODIFICATIONS HAVE ON THE CLASS RATES OF RETURN FOR PP&L'S RATE CLASSES?

A. I have shown the results of a cost-of-service study performed with each of my proposed modifications separately. These are shown in Exhibit___(CEJ-4), Schedule 3.

V. RATE DESIGN

Q. WHAT RATE DESIGN ISSUES WILL YOU ADDRESS?

A. I will respond to several statements made by PP&L witness Kasper.

1. Allocation of the revenue increase

Mr. Kasper has reiterated his support for his own proposal, but has offered no specific rebuttal to my proposal. The only relevant claim is that my proposed allocation of any revenue increase (as well as other parties) is not consistent with his cost study and will not move all customer classes closer to an equalized rate of return, as measured by his study. While that is true, my recommended treatment of any revenue increase is consistent with the cost study I support and recommend be adopted by the Commission.

2. Residential Customer Charge

Mr. Kasper claims to have rejected a lower increase in the customer charge than the 50 percent proposed by PP&L for several reasons. He has not addressed the issue I raised about the cost of billing, metering and services being below the level of the current customer charge and he continues to rely on the allocated cost of almost every distribution cost except O&M for lines, poles and transformers, but including overheads, such as administrative and general expense, customer information, uncollectibles, etc. On this basis, he asserts the result of instability in revenue recovery would ensue if the customer charge is not increased. It is true that if energy prices are higher and fixed customer charges lower, changes in energy consumption will result in changes in revenue, but that is insufficient reason to recover more revenue through the customer charge than the cost.

The other reasons provided by Mr. Kasper are unrelated to why PP&L should raise its customer charge by 50 percent. They are merely observations, such as that the customer charge has not been increased for 10 years, the increase should not ration access to the system and the proposed $7.20 per month customer charge would not be the highest in the state. These are not justification for the increase and do not address the reasoning in my direct testimony supporting continuation of the current customer charge.

3. Residential Energy Charges

Mr. Kasper claims the establishment of the third energy block is cost based and that even if the customer cost has been overstated by PP&L, the costs are then demand-related and should be recovered in early blocks of the residential rate. His assertion that the costs <u>should be</u> recovered in early blocks is not based on any facts in evidence and he has offered none.

For the average RS customer (who takes 880 kWh per month), there would be absolutely no difference whether the costs are recovered in the customer charge or in the first two of three energy blocks. In fact, over 90 percent of the full 200 kWh first energy block is taken by RS customers and over 60 percent of the proposed 600 kWh second block would be taken. This means that almost all residential customers would pay all of the charges in the first block in excess of the energy cost and most would pay almost all of the extra charges for the second block. PP&L would, therefore, recover almost all of the differences in the charges between the early blocks and the tail block.

The Company's proposal is tantamount to recovery of all of these costs in the customer charge. The Commission should reject the addition of a third energy block in the residential rate.

4. Residential Thermal Storage

Mr. Kasper has agreed with my proposal to close the current RTS rate, grandfather existing location and PP&L proposes to maintain the existing 2.9¢ per kWh differential between RS and RTS at least through December 31, 1999. PP&L is also planning to take steps to reduce the peak demand created by RTS customers. While I am not completely in agreement with the pledge to maintain the rate differential only for the next four years, I could accept that the Company would be free to propose a different treatment at that time based on then-current facts.

I have one major disagreement with PP&L's proposal. I believe the RTS rate should be closed at the time of issuance of the Commission's order. There is no reason to continue offering and promoting this service if its benefits cannot be sustained in the future. At the very least, if the Company's proposed date is accepted, applicants between now and December 31, 1995 should be informed of the conditions covering the rate before their application is accepted.

5. EDI/IDI Credits

In support of recovery from all customers of EDI/IDI credits provided to customers, Mr. Kasper presents what he characterizes as a "benefit/cost" analysis. His analysis here suffers from the same flaw that was in his direct testimony. His benefits all result from the assumption that none of this load would exist without the credits. As Mr. Kasper phrases it, "The change in total revenues for the EDI/IDI program is based on the <u>projected</u> loss of 20 industrial customers if the EDI/IDI program was not offered." [Emphasis added.] His only justification for projecting the loss of the customers absent the EDI/IDI program is his statement that "Participating customers demonstrated that the EDI programs contributed to retaining their facilities in PP&L's service territory by allowing them to produce at a lower incremental cost than competing plants." This is a broad sweeping claim for which he has offered no supporting documentation.

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY ON CLASS COST OF SERVICE AND RATE DESIGN?

A. Yes.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)))	DOCKET NO. R-00943271

SCHEDULES ACCOMPANYING THE

SURREBUTTAL TESTIMONY

OF

DR. CHARLES E. JOHNSON

ON CLASS COST OF SERVICE AND RATE DESIGN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 1995

EXETER

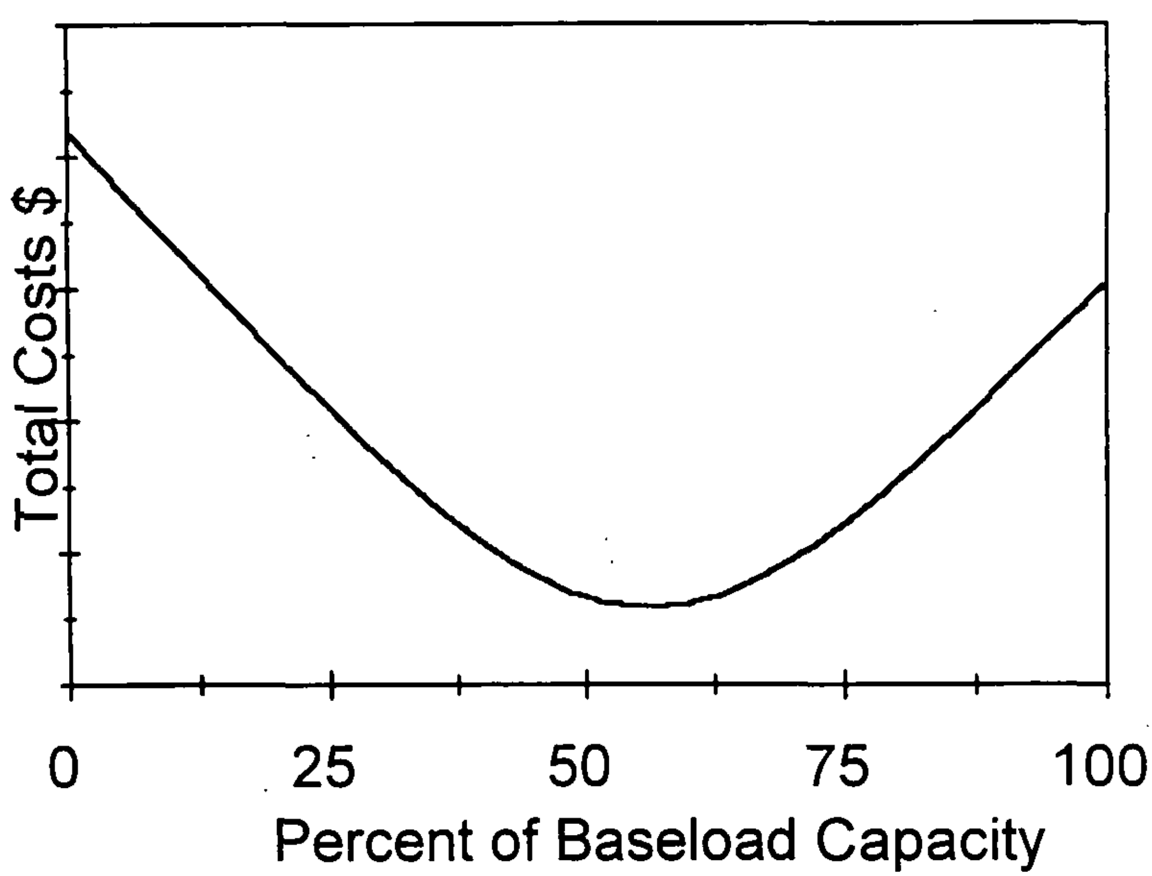
Associates, Inc.

12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

PAPUC Docket No. R-00943271
OCA Statement No. 3B
Exhibit__(CEJ-4)
Schedule 1
Page 1 of 1

Pensylvannia Power & Light Company

Annual Capital and Fuel Costs



PENNSYLVANIA POWER & LIGHT COMPANY

Peak and Average Allocation of Generation Plant
Net Investment to Selected Classes

Class (1)	Total[1] Net Plant per kW (2)	Demand[2] Related Net Plant per kW (3)	Energy Related Net Plant per kW (4)	kWh per kW (5)	Energy Related Net Plant per kWh (6)
RS	$569	$246	323	4,891	.0661
GS-1	618	246	372	5,630	.0661
LP-5	263	246	517	7,824	.0661
Total Pennsylvania Jurisdiction	$631	$246	385	5,827	.0661

[1]per Rebuttal Testimony of Brubaker, page 6.
[2]38.95 percent of jurisdictional amount.

PENNSYLVANIA POWER & LIGHT COMPANY

Rate of Return Under Each OCA-Proposed Cost Allocation Adjustment

Rate Class	PP&L[1] Study	OCA[2] Study	Peak and Average Adjustment	Minimum System Adjustment	Interruptible Credit Adjustment
RS	5.84	7.31	5.90	7.13	5.91
RTS	-2.36	-2.49	-1.13	-3.34	-2.39
GS-1	14.41	16.60	14.44	16.34	14.59
GS-3	9.93	8.67	11.40	7.44	10.10
LP-4	8.96	7.87	7.86	8.95	8.96
LP-5	5.34	3.09	3.32	5.34	4.92
LPEP	8.09	8.66	8.49	8.13	8.29
ISA	0.79	-1.69	-2.19	0.80	0.58
GH	5.75	6.01	9.27	3.44	5.83
SL/AL	4.72	3.60	3.92	4.36	4.73
Standby	24.58	22.34	21.93	24.44	24.92
PA Jurisdiction	7.31	7.31	7.31	7.31	7.31

[1]PP&L Exhibit JMK-2, pages 99 and 100.
[2]OCA Statement 3, Schedule 1.

OCA STATEMENT NO. 5A

5/25/95
Hbg
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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)	DOCKET NO. R-00943271

SURREBUTTAL TESTIMONY

OF

DR. CHARLES E. JOHNSON

ON DEPRECIATION

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 1995

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY	)))	DOCKET NO. R-00943271

SURREBUTTAL TESTIMONY
OF
DR. CHARLES E. JOHNSON
ON DEPRECIATION

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Charles E. Johnson. I am a Principal with Exeter Associates, Inc. Our offices are located at 12510 Prosperity Drive, Silver Spring, Maryland, 20904.

Q. ARE YOU THE SAME CHARLES E. JOHNSON WHO HAS PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. PURPOSE AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY ON DEPRECIATION?

A. I will respond to certain statements made by Pennsylvania Power and Light Company (PP&L) witnesses Krall and Hoch relating to depreciation and amortization. Specifically, I will address Mr. Krall's claims concerning the capital recovery of Holtwood, Sunbury and Martins Creek generating units, Mr. Hoch's claims concerning the replacement of modified sinking fund (MSF) depreciation for pre-1989 Susquehanna investment with a levelized approach, and Mr. Hoch's statements on the amortization of items of small value.

Q. WHAT IS YOUR POSITION ON THESE ISSUES?

A. My positions on the capital recovery of Holtwood 17, Sunbury 1 through 4 and Martins Creek 1 and 2 and the MSF treatment of pre-1989 investment in Susquehanna steam electric station are unchanged from my direct testimony. My position on the amortization periods for items of small value remains the same as in my direct testimony, except for one account, Laboratory Equipment. For this account, the amortization period should be shorter than I proposed in my direct testimony.

III. ADVANCE OF DEACTIVATION DATES

Q. ARE YOU SATISFIED WITH MR. KRALL'S RESPONSE TO ASSERTIONS THAT THE PROPOSAL TO SHORTEN THE LIVES OF HOLTWOOD, SUNBURY, MARTINS CREEK 1 AND 2 AND THE ASSOCIATED COMBUSTION TURBINES AND DIESELS WAS INAPPROPRIATE FOR RATEMAKING PURPOSES IN THIS PROCEEDING?

A. No. Mr. Krall made it clear during cross examination on March 21, 1995 that at the time his testimony was being prepared in October-November 1994, the Company made a decision to advance the deactivation dates for these generating units and memorialized that decision only in his testimony for this proceeding. No memorandum or other document was prepared. [Tr. 165] Contrary to Mr Krall's assertion that "appropriate" analytical support was performed (a topic I will return to later in this testimony), no studies, analyses, reports or memoranda were prepared from the time the Five-Year Upgrade plan for Coal-Fired Generation was prepared in May 1994, until PP&L's rate case was filed, and no documentation of any such decision exists outside the rate case until after the issue was raised by the parties in this proceeding.

Q. MR. KRALL CLAIMS THAT THERE ARE ANALYTICAL STUDIES SUPPORTING THE DECISION TO ADVANCE THE DEACTIVATION LIVES, BUT THAT YOU IGNORED THEM. WHAT IS YOUR RESPONSE?

A. Mr. Krall refers to PP&L's responses to OTS-RB-23D, OCA IV, Question 86 and PPLICA II, Question 13, which he describes as containing identical information. Two points should be made. First, these responses were prepared after Mr. Krall's testimony was prepared, so the documents could not have served as the basis for the decision to advance the deactivation dates. One is forced to conclude that, at most, PP&L personnel gave thought to the issue prior to receipt of the data requests, but committed nothing to paper.

Second, this response contains little information that was not in Mr. Krall's testimony, and the factual information in the response is unsupported. I have included the entire response as Exhibit___(CEJ-5), Schedule 1.

It is my belief that the analyses are insufficient for the Commission to accept as justification for such an important decision or for the imposition of $15 million additional expenses on Pennsylvania ratepayers. I continue to recommend that the Commission reject the Company's proposal to fully recover the capital invested in these plants by the earlier dates.

III. SUSQUEHANNA MSF

Q. WHICH OF MR. HOCH'S STATEMENTS ON THE MSF WILL YOU ADDRESS?

A. I will address the following assertions of Mr. Hoch:

- Mr. Kollen and I do not consider the effect of PP&L's new investment in Susquehanna in our analysis;
- Mr. Kollen and I attempt to anticipate post-future test year events;
- Levelized depreciation is consistent with straight line depreciation; and
- His corrections to OCA Exhibit___(CEJ-2).

Q. HAVE YOU CONSIDERED THE EFFECT OF NEW INVESTMENT IN SUSQUEHANNA IN YOUR ANALYSIS?

A. No. It would be inappropriate to do so. Nor have I attempted to anticipate post-future test year events.

Depreciation rates are set for the purpose of recovering the capital that has already been invested in utility plant, and to generally attempt to recover the capital over the useful life of the plant. Depreciable plant is that portion of the utility's current investment for which capital recovery is determined. Depreciation concepts do not extend to recovery of future investment. Moreover, the issue under consideration is the MSF method applied to pre-1989 Susquehanna investment. Any future investment would not be subject to the MSF.

As for attempting to anticipate post-test year events, I take his reference to be to my Exhibit___(CEJ-2), Schedule 1, in which I presented data from years subsequent to the test year. The entire purpose of presenting Exhibit___(CEJ-2), Schedule 1, which Mr. Hoch has corrected, was to show the effect of the Company's proposal on revenues received by PP&L during the next four years under several different circumstances. It in no way attempted to incorporate post-test year events in today's rates. Mr. Hoch's Exhibit DSH-3 will assist me in clarifying the point I was attempting to make at that time.

Exhibit DSH-3 shows that the depreciation booked by PP&L for pre-1989 Susquehanna investment would be the same and return on investment would be about the same over the period in question under either the MSF or the Company's proposed levelized approach, so long as rates were adjusted annually to reflect reductions in net plant. What is important is that if rates are not adjusted each year, revenue levels will be set to recover return at current levels of rate base and depreciation accruals will be set at test year levels of Susquehanna depreciation.

The test year level of pre-1989 Susquehanna depreciation requested is $173 million. As shown in Exhibit DSH-3, under the MSF, only $142 of depreciation would be booked in calendar 1995 and only $150 million would be booked under the levelized approach (representing a difference only for the last quarter of 1995). However, under PP&L's proposal, revenues from Pennsylvania ratepayers would have been set to recover the higher test year level of $173 million in depreciation expense. Because the test year is different from the calendar year, these comparisons are not exact (which was the problem I encountered constructing Exhibit CEJ-2, Schedule 1), but allowing for that imprecision, return for the test year would be set at about $296 million and depreciation expense would be set at $173 million for a total of $469 million in total capital recovery in rates from Pennsylvania ratepayers.

The $469 million in rates to cover the requested annual capital recovery exceeds the amount that would be required in the test year under the MSF by over $30 million. Examining Exhibit DSH-3, it can be seen that the $469 million in test year capital recovery exceeds the capital recovery under the levelized approach (assuming annual rate proceedings) by the following amounts:

1995	$24 million
1996	$19 million
1997	$36 million
1998	$54 million

In other words, if the PP&L levelized Susquehanna depreciation proposal is used to set rates, it is likely that rate reductions would be appropriate in each future year. It might also be noted that PP&L does reach beyond the test year to develop its proposed levelized approach.

Q. HOW DO YOU RESPOND TO MR. HOCH'S STATEMENT THAT LEVELIZED DEPRECIATION IS CONSISTENT WITH STRAIGHT LINE DEPRECIATION?

A. It is true, but irrelevant. One should never lose sight of the fact that there are two aspects to depreciation rates that are not necessarily identical. One aspect is the annual depreciation booked on the Company's accounting records. The amount being booked over the years has its impacts. For example, pre-1989 Susquehanna investment has been booked at a slower rate under the MSF than it would have under straight line depreciation. As a result, pre-1989 Susquehanna net plant is larger today than it would have been if straight line depreciation had been used. This means that return on pre-1989 Susquehanna investment is greater in the test year than if straight line depreciation had been used.

The second aspect of depreciation rates is the amount used as depreciation expense in the test year to set jurisdictional revenue levels. The current rates were based on a test year ten years ago, at which time the annual depreciation expense for pre-1989 Susquehanna investment was lower than it is today. Even though rates were based on the MSF level ten years ago, the amount being booked each year was per the MSF schedule. Thus, it should be assumed that the Company will book the appropriate level of depreciation, whatever basis is used for setting rates. The only question here is the appropriate level of depreciation expense for inclusion in the test year.

As I explained both here and in OCA Statement No. 5, it would be inappropriate to set depreciation expense for the test year to include levelized amounts for pre-1989 Susquehanna investment. The Commission should reject PP&L's proposal and include the MSF level in the test year for developing rates for Pennsylvania jurisdictional ratepayers.

V. <u>AMORTIZATION OF ITEMS OF SMALL VALUE</u>

Q. WHAT ISSUES ARE RAISED BY MR. HOCH REGARDING YOUR PROPOSED AMORTIZATION PERIODS FOR ITEMS OF SMALL VALUE?

A. Mr. Hoch raises the following issues:

- He is unclear about the basis for my recommended amortization periods;
- I relied on a stale study;
- My characterization of his analysis is unfair;
- I do not understand or have misconstrued fundamental depreciation concepts; and
- I inexplicably proposed a 40-year amortization period for laboratory equipment.

Q. IS HE CORRECT IN ANY OF HIS CRITICISMS?

A. With regard to my proposed amortization period for account 395, laboratory equipment, he is correct that a 40-year amortization period is inappropriate. I propose to revise the amortization period for account 395 from 40 to 20 years based on his discussion and a review of the evidence. Consistent with this amortization period, I also have revised the amount of amortization to be included in the test year for account 395 from $113,139 to $226,278. I have provided this revision to OCA accounting witness Catlin for his calculations. His other criticisms are incomplete observations, incorrect statements or irrelevant.

Q. DID YOU EXPLAIN THE BASIS FOR YOUR RECOMMENDED AMORTIZATION PERIODS?

A. I explained the basis for my recommendations in OCA Statement 5, page 14. My recommendations were based on all of the information provided by PP&L, as described there.

Q. WERE THE DATA ON WHICH YOU RELIED STALE?

A. No. I did use data from the depreciation study on which current rate levels were set, but in no case did I rely exclusively on that older data. It is instructive to compare PP&L's proposed amortization periods with the lives from the Company's last service life study provided in response to OTS-RB-14D. This comparison is shown in Exhibit___(CEJ-5), Schedule 2. Note that in every instance save account no. 391.6, General Computers, the PP&L requested amortization is shorter than the service life from the last study. Many of the service lives from this study are much closer to the amortization periods I recommend than to the PP&L-proposed periods. For example, the latest service life for account 391.2, furniture, is 40 years, which exceeds my recommended 30-year amortization, and is twice the 20-year amortization proposed by PP&L.

Q. IS YOUR CHARACTERIZATION OF HIS ANALYSIS UNFAIR, AS ASSERTED BY MR. HOCH?

A. No. Mr. Hoch described his analysis as being based on interview notes made during meetings with responsible groups within the Company regarding estimated useful life of specific equipment within each account. [PP&L Response to OCA III, Q. 10] I have no quarrel with that.

Q. HOW DID MR. HOCH DETERMINE THE AMOUNT OF AMORTIZATION FOR ACCOUNT 391.2 TO INCLUDE IN TEST YEAR RATE LEVELS?

A. Mr. Hoch inappropriately used the unrecovered balance in the account divided by the difference between his proposed amortization period and the average attained age of the account. This has nothing to do with the proper level to include in the test year.

Q. PLEASE EXPLAIN.

A. Under remaining life depreciation procedures, the unrecovered balance would be divided by the remaining life of the account to determine the appropriate level of depreciation expense to include in test year expense. Mr. Hoch has mixed this concept with concepts that are used in amortizing plant over an amortization period.

He has not used the remaining life from a life study in his calculation. He carefully characterizes the "remaining recovery period" that is derived from subtracting the average attained life of 15 years from the full 20-year recovery period proposed by PP&L. Had he used the 40-year life from the last life study, the remaining recovery period would have been 25 years and the expense level in the test year would have been $641,768, a value much closer to the value I developed.

Q. IS YOUR FAILURE TO CONSIDER THE AGE DISTRIBUTION AND OTHER PARAMETERS OF THESE ACCOUNTS REASON TO REJECT YOUR PROPOSAL?

A. No. The proper way to make the change from normal depreciation methods to amortization of these accounts is to address the going-forward amortization levels separate from any problems that might exist due to differences between actual and theoretical reserve balances or age distribution of plant. Combining these concepts has led Mr. Hoch into problems with his numbers.

First, on a going-forward basis, there are several assumptions that need to be made. One is that the amount of plant in each account is the proper level to use in developing amortization levels for test year expenses. There is no reason to use a different level than is on the Company's books for this. Second, as I explained above, the proper level of amortization to include in test year expense is the plant balance divided by the amortization period.

Second, any problems that may be created due to age distribution or existing reserve balances have to be addressed. It should be kept in mind that there may be none. That is, if depreciation recovery in the past was proper, the change to amortizations in the future would be seamless. What I mean by that is that as existing vintages are retired and their depreciation levels decline, the amount of plant being amortized will increase and the amortization will generally offset the reductions in depreciation. Future vintages would be amortized and existing plant would continue to be depreciated, so that the total expense would be roughly at the level included in the test year.

What Mr. Hoch has attempted to do is to ignore the appropriate amortization level to include on a going-forward basis and to try to recover the current unrecovered balance in each account over a period only characterized as the remaining recovery period. There is nothing in his approach that resembles normal ratemaking practice.

Q. HAVE YOU ADDRESSED ANY PROBLEMS THAT HAVE BEEN CREATED BY AGE DISTRIBUTION OR EXISTING RESERVE BALANCES?

A. No. PP&L has not performed life studies on these accounts, so it is not possible to determine if problems arise for these reasons. PP&L was asked to provide life studies in OCA III, Q.8 and provided only the retirement rate analysis I largely relied on in determining my proposed amortization periods. Absent information that would enable me to determine the potential existence of problems, I have assumed that none exist.

Q. HOW DO YOU RESPOND TO HIS STATEMENT THAT YOU DO NOT UNDERSTAND OR HAVE MISCONSTRUED FUNDAMENTAL DEPRECIATION CONCEPTS?

A. Mr. Hoch has misinterpreted my statements to draw an incorrect picture of my understanding and knowledge. He has also used inappropriate amortizations for test year levels that overstate the cost of service to Pennsylvania ratepayers.

The appropriate level of amortization to include in the test year for ratemaking purposes would be the gross level in each account divided by the appropriate amortization period. Had PP&L been employing amortizations in the past, the amount of amortization booked for each account would be the gross plant divided by the amortization period.

For example, account 391.2, furniture, currently contains $16,044,199. If my 30-year amortization period had been used during the past 30 years, each vintage during that period would be amortized 1/30th each year, including the current year. Thus, it would be appropriate to include 1/30th of the $16,044,199, or $534,807 in test year expense for ratemaking purposes. The level of amortization included in the test year by Mr. Hoch is $2,068,390, nearly four times as large.

Q. DOES THIS COMPLETE YOUR TESTIMONY?
A. Yes.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

	)	
PENNSYLVANIA POWER & LIGHT COMPANY	)	DOCKET NO. R-00943271
	)	

SCHEDULES ACCOMPANYING THE

SURREBUTTAL TESTIMONY

OF

DR. CHARLES E. JOHNSON

ON DEPRECIATION

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 1995

PENNSYLVANIA POWER & LIGHT COMPANY

Response to Interrogatories of
the Office of Consumer Advocate, Set IV
Question 86

Pennsylvania Power & Light Company
Response to Interrogatories of
the Office of Consumer Advocate, Set IV
Dated February 1, 1995

Docket No. R-00943271

Q.86. If not provided in response to the previous question, please provide any economic analyses or other studies performed in conjunction with the decision to move up the retirement dates for Holtwood 17, Martin's Creek 1 and 2, and Sunbury generating facilities.

A.86. *The studies of the continued operation of the Holtwood* 17, *Martins Creek* 1 and 2, and Sunbury generating units included in the Five-Year Upgrade Plan for Coal-Fired Generation which is provided in response to Question 85 of Interrogatories of the Office of Consumer Advocate, Set IV, Dated February 1, 1995 are the starting point for PP&L's proposed retirement dates for those units.

Referring to the analyses for Sunbury (Section 5), Martins Creek (Section 6), and Holtwood (Section 7), the dominant feature of each is that, while continued operation is favored over retirement, the margin by which continued operation is favored is relatively small. This implies greater exposure to shutdown for units at these stations than for units at Montour (Section 3) or Brunner Island (Section 4) as a result of uncertainties in the estimates used in the analyses and events which cannot currently be foreseen. In particular, the Company is concerned that the need for significant reductions of NOx emissions under Title I of the 1990 Clean Air Act Amendments and reductions of emissions of air toxics under Title III of the 1990 Amendments are two cost exposures, not included in the May, 1994 analyses, which could erode the economic benefit of continued operation through 2013. Reductions under both Titles appear to be scheduled for 2003, if determined to be necessary.

The Company's current estimate of the exposure for NOx is that Selective Catalytic Reduction (SCR) systems could be required. This technology is not commercially proven on the types of coal which PP&L's units burn, but an estimate of the cost exposure (in 1994 dollars) for units like Martins Creek 1 and 2 is $24 million in capital with annual operating costs of $6 million. Although it is not clear what pollutants, if any, are to be controlled and what control strategy might be required until the air toxics studies are complete, the

Company estimates that the exposure might include the installation of high-efficiency bag filters with a cost exposure for units like Martins Creek 1 and 2 of \$60 million in capital (2003 vintage dollars). Similar exposures exist for Holtwood 17 and the Sunbury units.

PENNSYLVANIA POWER & LIGHT COMPANY

Comparison of PP&L-Proposed Amortization Periods with Lives from Last Service Life Study

	Account	Requested[1] by PP&L	Service[2] Life Study
391.2	Furniture	20	40
391.4	Mechanical Equipment	15	19
391.6	General Computers	10	5
393.0	Stores	30	34
394.0	Tools - L&S Line Crews	20	26
394.4	Tools - Construction	20	26
394.6	Tools - Other	20	26
394.8	Garage Equipment	20	26
395.0	Laboratory Equipment	15	23
398.0	Miscellaneous Equipment	25	29

[1]Attachment V-B-2.
[2]PP&L Response to OTS-RB-14D.