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SECRETARY'S OFFICE
Public Utility Commission

Pennsylvania Public Utility Commission

vs.

Philadelphia Electric Company

Docket No. R-850152

Rebuttal Testimony Of

Raymond C. Williams

Re: Distribution of Revenue Increase and Rate Design

DOCKETED
MAR 13 1986



February 1986

Rebuttal Testimony of Raymond C. Williams

Q. Are you the same Mr. Williams who has previously filed direct testimony in this proceeding?

A. Yes. I have previously submitted direct testimony identified as Statement 17.

Q. What is the purpose of this rebuttal testimony?

A. This rebuttal testimony addresses the distribution of the revenue increase as proposed by Mr. Figley, Mr. Oliver and Mr. Pollock; the essential needs rate proposal of Mr. Oliver and Mr. Grier; the time of use metering proposal of Mr. Larson; the Rate RH pricing criticism of Mr. Oliver and the Amtrak supply question raised by Mr. Rudden.

Q Mr. Williams, have you compared the proposed distribution of the revenue increase to the various classes as proposed by Messrs. Oliver, Figley and Pollock?

A. Yes, I have prepared Schedule A to show a comparison of these three proposed distributions of the revenue increase to that of the Company. In order to bring all of the proposed increases to a comparable basis it was necessary to subtract the fuel rollout of 0.7505¢/kWh for each class from the proposals of Mr. Figley and Mr. Pollock. For Mr. Oliver it was also necessary to subtract the growth adjustment as shown on page D-3 of TPH-2. As presented this schedule shows the increase from the present customer and class revenue level to that level which the customer and class would pay after the increase with the estimated fuel savings. This is the same dollar and percent increase shown on page A-5 of Exhibit TPH-2.

Mr. Figley and Mr. Oliver basically accept the Company's proposal to allocate an equal percentage increase to all classes including fuel costs. However, their proposals to allocate a substantial portion of production and transmission costs on an energy basis reduces the rate of return of Septa and Amtrak as well as the off peak classes such as Rate OP, SLP and SLS. Specifically, Mr. Oliver's proposal reduces the Company's proposed increase to the residential class by increasing Septa and Amtrak plus the off peak loads of Rates OP, SLP and SLS. Mr. Figley would reduce the Company's proposed increase to Rates R, GS, PD and HT by increasing Septa, Amtrak and the off peak loads of RH, OP, POL, and SLP. In my view, these proposals should be rejected because they are inconsistent with the Company's cost of service study which has been repeatedly approved by the Commission, and because it would discourage off-peak usage as explained in Mr. Sundermeir's Rebuttal Testimony.

Mr. Pollock proposed to exclude all fuel costs from the allocation. The Company considered this approach, which was used in its last two cases, but rejected it in this case because of the resulting disparity of increases to customer classes, as demonstrated by Mr. Pollock's 35.5% increase for Rate R and 23.2% increase for Rate HT.

Q. Do you agree with Mr. Oliver's proposed blocking of the residential rate for essential use?

A. No. Providing reduced pricing for essential use through the residential rate is an inefficient and ineffective method of targeting help to those customers who really need help because of their low income. Many low income customers have monthly use far in excess of Mr. Oliver's proposed 350 kWh. For example, Schedule B shows that 67% of those in our Customer Assistance Program have use above 400 kWh per month. Thus, Mr. Oliver's proposed limitation of the increase to the first 350 kWh of usage will not be effective and in fact would penalize low income customers with high usage and benefit low usage customers with high income levels.

Q. Do you agree with Mr. Oliver's proposal for a water heating block of 350 kWh in the Residential rate?

A. No. Most of Philadelphia Electric electric water heating is provided on an off peak basis on Rate OP. There are 102,000 water heating customers served on Rate OP who would receive no net increase under the Company's proposal but would be increased 28.5% under Mr. Oliver's proposal.

Those relatively few water heating customers that may be served on the Rate R rather than OP have large heating consumption or are willing to pay the premium for uninterrupted water heating service. The Company does not have any record of which Rate R customers have electric water heaters. Therefore, to implement Mr. Oliver's proposal would require an on site inspection of each customer claimed installation.

Q. Do you agree with Mr. Grier's statement that most low income households are small, contain few children and are usually elderly?

A. No. That has not been the experience of the PE Customer Assistance Program. Schedule C shows the current customer demographics of the Customer Assistance Program. Of the 704 customers accepted for the program 347 or 49% are single females with children.

Q. Has there ever been a specific study done of the relationship between electrical usage and household income in the Philadelphia Electric service territory?

A. Yes. In 1976, at the request of the Pennsylvania Public Utility Commission at R.I.D. 129, National Analysts, a division of Booz, Allen and Hamilton, conducted such a survey.

Q. What was the finding of that study?

A. That study found that family size has a far greater influence on usage than does family income. The findings of that study were included in the PaPUC final report on 76 P.R.M.D.7 in Exhibit 10-9.

Q. Do you agree with Mr. Grier's position that most low income residential customers use less than 500 kWh and therefore limitation of the increase to this block would be the best way to help low income customers.?

A. No. Philadelphia Electric's experience with its Customer's Assistance Program (CAP) shows that 48% of the low income customers on that program use more than 500 kWh per month

(See Schedule B). Therefore, any limitation of increase to the first 500 kWh block will not provide the desired benefit to 48% of the customers that need help. If any of the benefit to the first 500 kWh block is achieved by increasing the rate for use over 500 kWh it will further disadvantage 48% of the low income customers.

Q. Does the PaPUC final order in the recent Pennsylvania Power and Light Company Rate Structure investigation at Docket I-830374 draw the same conclusion?

A. Yes, on page 11 of the final order in that investigation the conclusion is as follows:

"The proposals of the OCA and Trial Staff to assist low-income customers by charging less than the cost rates for specified quantities of electricity are based upon the assumptions that all low-income and fixed-income customers use very little electricity while all affluent customers use a great deal of electricity. In a 1976 Generic Rate Structure Investigation, the Staff, in rejecting this concept of lifeline rates, noted in its Final Report:

> As a result of this investigation it has been concluded that a relationship between average kWh usage and income does exist. However, the variance of range of kWh usage within any income level precludes using kWh alone as a means of accurately determining the level of income. Hence the general lifeline concept will penalize

many low income consumers who need assistance, while benefitting others not in need of aid. Final Report, 76 P.R.M.D. 7, at p. 21.

In a recent study by the Bureau of Consumer Services, it was shown that payment troubled customers generally use more electricity than average residential utility customers. It is our opinion, and we so find, that the Staff and the OCA proposed rate design modifications have one fatal flaw; that is, they would, in some cases, hurt those low-income customers who need help and would benefit some affluent customers who have absolutely no need for the benefit. Seeing no need to consider this matter again in rate proceedings we reject the ALJ's recommendation that we do so."

Q. Is there any cost justification for Witness Oliver's essential use proposal?

A. No. As can be seen in Schedule D, the revenue curve for Rate R is below the cost curve up to approximately 5500 kWh per year (460 kWh per month). If the pricing of the first energy block is lowered, the revenue for the low use customer will move further below the costs.

Q. Does this cost curve reflect the lower demands of the low use customers?

A. Yes. The demands used to develop the cost curves are from actual field test data of customers ranging from low to high monthly use.

Q. Mr. Oliver also characterizes Rate R-H as a promotional rate and claims that there is no tie between the winter end block price of this rate and actual costs. Is he correct?

A. No. Rate R-H is not a promotional rate. As can be seen on page 6A of Exhibit WFS-1, the rate-of-return of Rate R-H under proposed rates is 16% higher than the system average rate-of-return. Also, as shown in Schedule E, the revenue curve is higher than the cost curve for Rate R-H customers using over approximately 6,000 kWh per year. This is a clear indication that, if anything, the winter end block price should be lowered, not raised as proposed by Mr. Oliver.

Q. Mr. Williams, is the differential in Rates R and RH justified in your view?

A. Yes. Mr. Oliver has referred to the winter RH rate as a "promotional" rate. This is simply not true. The load characteristics of Rate RH are markedly different than Rate R. Rate R peaks in the summer near the time of the Company's system peak. By contrast Rate RH peaks in the winter. This increased winter usage by the RH class improves the Company's annual system load factor and provides more efficient utilization of the Company's facilities. These advantageous and unit cost reductive usage characteristics should be recognized in rate design. Moreover the winter tail block usage in Rate RH does not contribute to the Company's system peak and does not cause the incurrence of demand related costs. Mr. Oliver's justification for a substantial increase in the winter tail block of Rate RH is based entirely in his proposal to allocate most of the capital related costs of Limerick #1 on the basis of the energy use of each class.

Q. Mr. Williams, do you have any comments with regard to the testimony of Mr. Rudden on behalf of Septa/Amtrak?

A. Yes. Mr. Rudden believes that an adjustment should be made to the cost allocation factor that is used to allocate production and transmission plant and expenses to Septa/Amtrak. He believes that an adjustment to the demands registered at Perryville and Thorndale is justified.

Q. Do you agree with Mr. Rudden on this issue?

A. No. The demands at Perryville and Thorndale have been included in every cost to serve study submitted by the Company and accepted by the Commission. The inclusions of these demands is justified for several reasons. The energy flow in and out of the PECo system is a transaction on the PJM Interconnection System that is handled in precisely the same manner as any other PJM interchange transaction. The demands at Perryville and Thorndale are part of the PECo system load, the same as demands recorded at other interconnection points.

It is was judged to be justifiable to exclude theloads at Perryville and Thorndale, it would be logical to exclude load at all other interconnection points. If such exclusion is made it would be impossible to develop a meaningful cost to serve study. The fact that the energy flow may be into the PECo system at certain times does not relieve the Company of the responsibility to provide this load when required, and it gives Amtrak the added reliability of two sources of energy at these delivery points.

Q. Mr. Rudden has indicated that a change in the cost allocation factor would reduce Amtrak's revenue requirement by $5 or $6 million. Is he correct?

A. The fact is that Mr. Rudden's proposal only reduces Amtrak's revenue requirement and has no effect on total revenue requirement; therefore, any reduction in revenue that would result from such adjustment would have to be recovered from other ratepayers because the total PECo load remains the same.

Q. Would Philadelphia Electric have any objections if the Perryville and Thorndale interconnection points on the Amtrak transmission system were opened so that there would not be any power interchange at these points?

A. No. These interconnection points are for the convenience of Amtrak. Any power interchanged at these points is used by Amtrak, it is not fed back into the PE 60 Hertz system.

Q. Do you have any comments on Mr. Larson's proposal to make the time of use energy adjustment available to GS and PD customers as it is presently available to Rate HT customers?

A. Yes. The time of use energy adjustment is presently <u>mandatory</u> not just available for Rate HT customers of 2000 kW or more. This is appropriate because only those customers with less than average energy cost, that is more off peak than the average, would elect the time of use adjustment on a voluntary basis and the net result would be a loss of revenue to the Company. The logical way to extend time of use energy adjustment would be to lower the threshold for applicability of the mandatory time of use adjustment from the present 2000 kW level down to the 150 kW level recommended by Mr. Larson. Such as extension would include about 200 customers on Rate HT above 1000 kW and about 3000 customers on Rates HT, PD and GS below 1000 kW. Time of use metering with half-hour recording would be required for the 200 Rate HT customers above 1000 kW at a cost of about $2000 per installation for a total of $400,000. For the 3000 Rate HT, PD and GS customers below 1000 kW electronic metering for the peak and off peak period demands and energy would cost about $900 per installation for a total of $2.7 million. Therefore the total cost to make the time of use energy adjustment available down to the 150 kW demand level would be about $3.1 million. This is an expensive way to provide a price signal to these customers.

The Company already offers the night service rider to all GS and PD customers to encourage a reduction in on peak demand. With this filing the Company has proposed a significant reduction in the last block of Rate GS for use over 400 hours per month to more properly reflect the off peak energy use of such a customer.

Q. Does that complete your rebuttal testimony at this time?
A. Yes.

## Comparison of Revenue Distribution to Classes

| | Company | | Figley | | Pollock | | Oliver | |
|---|---|---|---|---|---|---|---|---|
| Rate | Million | % | Million | % | Million | % | Million | % |
| R | $219.2 | 29.6% | $212.2 | 28.7% | $262.2 | 35.5% | $211.8 | 28.6% |
| RH | 33.0 | 25.9 | 36.6 | 28.7 | 34.1 | 26.7 | 33.0 | 25.9 |
| OP | 0 | 0 | 7.5 | 28.7 | (0.9) | 0 | 7.4 | 28.5 |
| POL | 0 | 0 | 0.4 | 28.7 | 0 | 0 | 0 | 0 |
| GS | 102.2 | 29.6 | 98.9 | 28.7 | 96.2 | 27.9 | 92.2 | 26.7 |
| PD | 56.6 | 29.6 | 54.8 | 28.7 | 50.1 | 26.2 | 56.6 | 29.6 |
| HT | 255.1 | 29.6 | 247.1 | 28.7 | 200.5 | 23.2 | 255.1 | 29.6 |
| EP-A | 3.7 | 12.7 | 4.8 | 15.2 | 5.4 | 18.4 | 5.0 | 15.8 |
| EP-S | 2.9 | 14.9 | 4.1 | 20.5 | 4.7 | 23.2 | 6.8 | 33.8 |
| SLP | 0 | 0 | 4.3 | 28.7 | 2.7 | 18.2 | 1.7 | 11.3 |
| SLS | 0 | 0 | 0 | 0 | 3.6 | 20.0 | 1.0 | 5.5 |
| TL | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| BLI | .002 | 28.6 | 0 | 0 | .001 | 14.3 | .002 | 28.6 |
| RR | .09 | 29.1 | 0 | 0 | .089 | 29.1 | .089 | 29.1 |
| Total | $670.1 | 28.2% | $670.7 | 28.1% | $658.7* | 27.7% | $670.7 | 28.1% |

* - Mr. Pollock's proposal allocates an additional $12 million of the rate increase to the "Other Utilities" class. This change reduces the amount of the increases allocated to the listed classes from $670.7 million to $658.7 million.

Customer Assistance Program

| Average Monthly kWh Consumption | Number of Customers | Percentage of Customers |
|---|---|---|
| 1- 99 | 10 | 1 |
| 100- 199 | 30 | 4 |
| 200- 299 | 67 | 9 |
| 300- 399 | 136 | 19 |
| 400- 499 | 135 | 18 |
| 500- 599 | 112 | 15 |
| 600- 699 | 74 | 10 |
| 700- 799 | 45 | 6 |
| 800- 899 | 29 | 3 |
| 900- 999 | 29 | 3 |
| 1000-1099 | 15 | 2 |
| 1100-1199 | 9 | 1 |
| 1200-1299 | 6 | 1 |
| 1300-1399 | 8 | 1 |
| 1400-1499 | 10 | 1 |
| 1500-1599 | 5 | 1 |
| 1600-1699 | 2 | 1 |
| 1700-1799 | 3 | 1 |
| 1800-1899 | 4 | 1 |
| 1900-1999 | 3 | 1 |

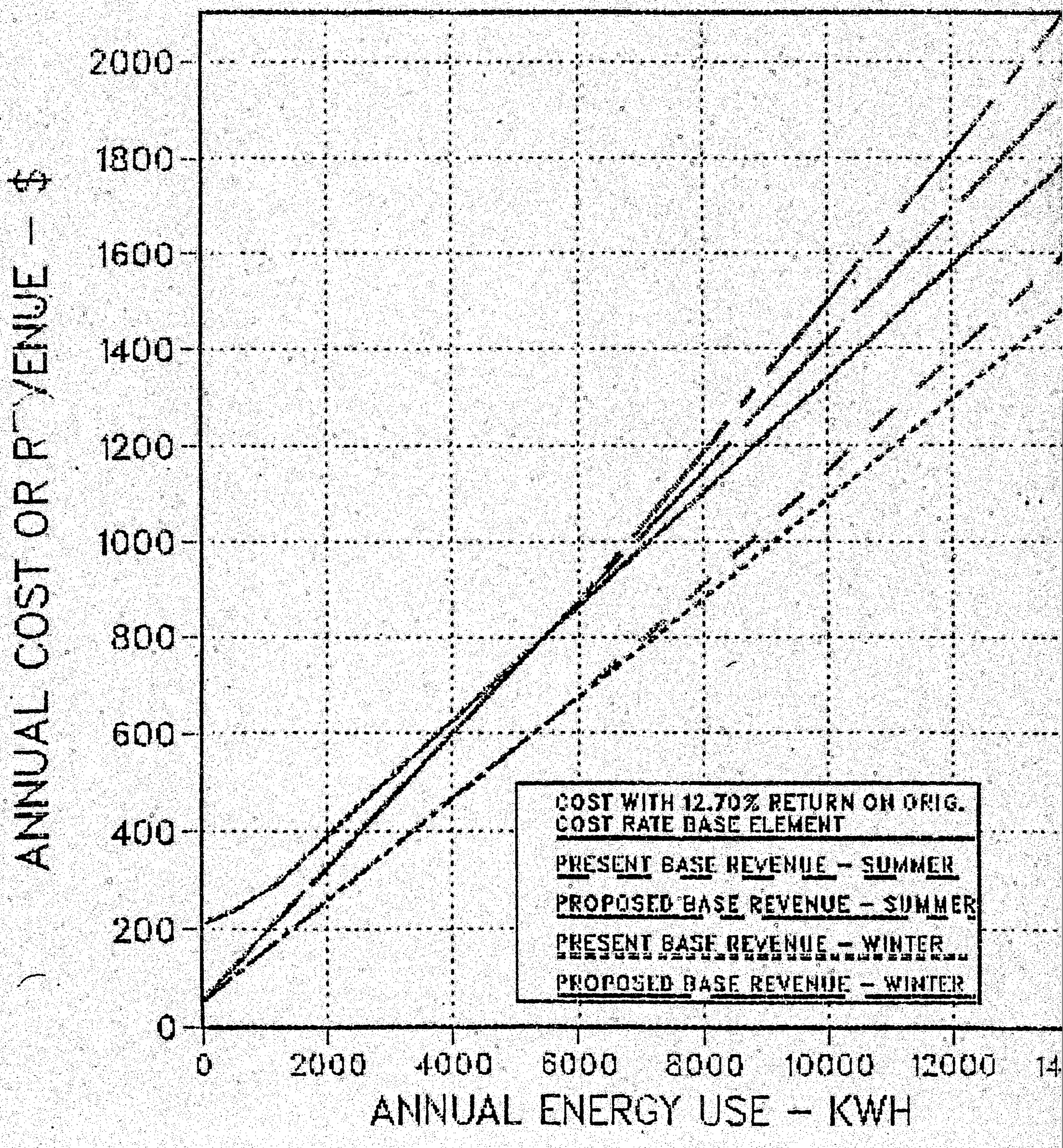
## Customer Assistance Program

## Customer Demographics

| | Customers Contacted | Customers Accepted |
|---|---|---|
| Single Male - Sr. | 29 | 11 |
| Single Male | 227 | 31 |
| Single Male/1 Child | 55 | 5 |
| Single Male/2 or More Children | 57 | 4 |
| Single Female - Sr. | 169 | 38 |
| Single Female | 464 | 114 |
| Single Female/1 Child | 762 | 135 |
| Single Female/2 Children | 789 | 132 |
| Single Female/3 or More Children | 672 | 80 |
| Couple - Sr. | 74 | 12 |
| Couple | 242 | 20 |
| Couple/1 Child | 312 | 42 |
| Couple/2 Children | 396 | 37 |
| Couple/3 or More Children | 469 | 33 |
| 3 or More Adults | 150 | 5 |
| 3 Adults/with Children | 194 | 5 |
| TOTALS | 5064 | 704 |

PHILADELPHIA ELECTRIC COMPANY
ELECTRIC OPERATIONS

RATE R
ANNUAL COST BASED ON TWELVE MONTHS
ENDING JUNE 30, 1986 AND TARIFF NO. 26
AND PROPOSED REVENUE



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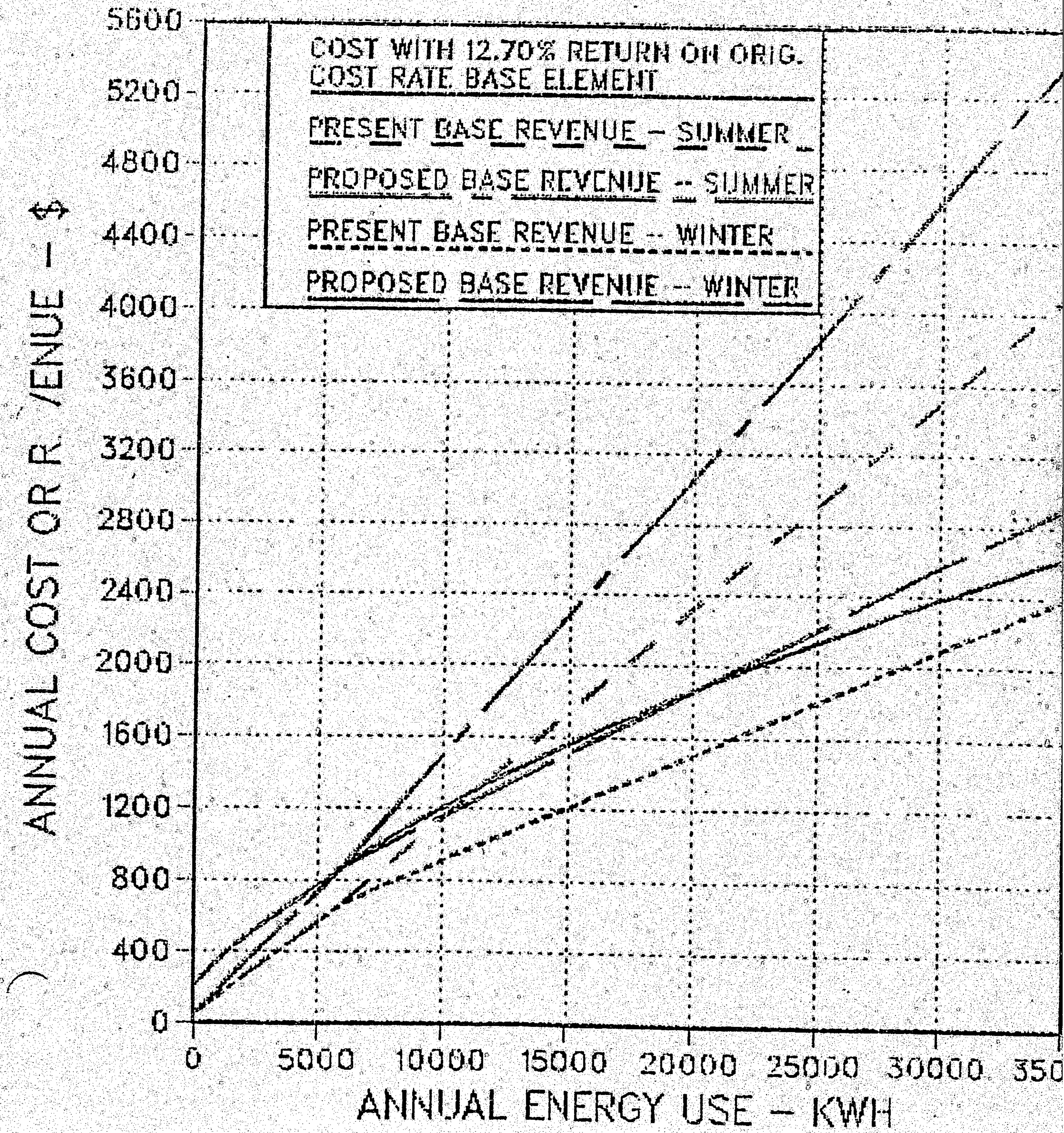

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PENNSYLVANIA PUBLIC UTILITY COMMISSION
v. PHILADELPHIA ELECTRIC COMPANY,
DOCKET NO. R-850152

# REBUTTAL TESTIMONY OF WILLIAM F. SUNDERMEIR

CLASS COST ALLOCATION,
UNIT COST STUDY
AND RATE DESIGN

DOCKETED

MAR 13 1986

FEBRUARY 1986

Rebuttal Testimony of William F. Sundermeir

Q. Mr. Sundermeir, what is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the opposing parties' criticisms of the Company's proposed cost of service study and rate design.

Q. Mr. Oliver on behalf of OCA, Dr. Wirtshafter on behalf of UP/UUC, Mr. Figley on behalf of the Pennsylvania Business Utility Users Group (PBUUG) and Mr. Sterzinger on behalf of CEPA have submitted testimony opposing the Company's four coincident peak methodology for the allocation of production plant. Do you agree with their criticisms and alternative proposals?

A. No, I do not. For the reasons stated in my direct testimony, I believe that the coincident peak method using the average of the demands on the peak day in each of the four summer months is a reasonable and appropriate allocation method for PECo. It is generally accepted that costs are allocated to classes of service based on the elements that cause the cost or cause the cost to vary. Despite arguments to the contrary, production plant is installed to satisfy the demand requirements of the system. These costs are fixed, they are related to the capacity of the equipment and they do not vary with energy use. There is no justification for allocating these costs on an energy basis.

Q. But isn't it true that energy costs vary depending on the type of generation that is installed? For example, a combustion turbine has a high energy cost while a nuclear unit such as Limerick has a low energy cost?

A. Yes. As a result of the operation of Limerick instead of the operation of a combustion turbine, the total system energy costs are lower. These lower energy costs vary with the system energy output and, therefore, are properly allocated to classes-of-service on the basis of energy consumption. In summary, the fixed capital costs of production plant are allocated on the basis of demand while the variable energy costs that result from various types of generation are allocated on the basis of energy.

Q. Is the proposal to allocate a portion of production plant on the basis of energy something new?

A. No. This issue has been extensively litigated in at least four prior PECo rate cases, and the Commission did not adopt an energy allocation of production plant in any of those cases.

Q. Would a change in the allocation method to include an energy allocation be justified due to the inclusion of Limerick #1 in rate base?

A. No. The Company currently has four nuclear units (Peach Bottom 2 & 3, Salem 1 & 2) included in rate base and none of the capital costs of these units is allocated on the basis of energy. As recently as the Company's last electric rate case (Docket No. R-842590) when Salem #2 was added to rate base, Mr. Miller, on behalf of OCA, proposed an energy allocation that is almost precisely the same as that proposed by Mr. Oliver and Mr. Sterzinger in this case. The proposal was rejected by the Commission.

Q. Are there any significant disadvantages to an allocation of production costs on the basis of energy?

A. Yes, there are a number of disadvantages. As stated on page 9 of Dr. Wirtshafter's direct testimony, an energy allocation results in significantly greater costs allocated to off-peak users. This can be illustrated by comparing the rates of return for rates with off-peak type service under the peak and average method proposed by Mr. Oliver to the rates of return developed by the Company. The following table shows the comparison.

| Rate | | OCA | PECo |
|---|---|---|---|
| OP | | 5.69% | 30.98% |
| Street Lighting | - SLP | 8.07 | 11.12 |
| | - SLS | 11.02 | 13.15 |
| | - Other | 11.94 | 18.95 |
| R-H | | 12.48 | 14.69 |

The effect of the lower returns for these off-peak services would be to require larger rate increases than those proposed by the Company. Such increases would tend to discourage off-peak use.

Q. Are there other disadvantages to an energy allocation of production plant?

A. Yes. This type of allocation would have a significant impact on the design of Rates HT and PD. To illustrate this point I have calculated the pricing for Rate HT that would result from Mr. Oliver's proposed allocation method. The following table shows a comparison of the pricing of Rate HT using Mr. Oliver's method and pricing developed by Mr. Figley and Dr. Wirtshafter to the pricing proposed by the Company.

| Rate HT | UP/UUC | OCA | PBUUG | PECo |
|---|---|---|---|---|
| Customer Charge | \$264.15 | \$264.15 | \$230.20 | \$264.15 |
| Demand Charge | \$5.77/kW | \$6.35/kW | \$6.18/kW | \$9.44/kW |
| First 150 Hours Use | 9.40¢/kWh | 9.30¢/kWh | 9.28¢/kWh | 9.64¢/kWh |
| Next 150 Hours Use | 7.64¢/kWh | 7.51¢/kWh | 7.33¢/kWh | 6.68¢/kWh |
| Additional | 5.91¢/kWh | 5.75¢/kWh | 5.41¢/kWh | 3.75¢/kWh |

As shown above, under the proposals by the intervenors there is a significant decrease in the demand charge and a significant increase in the end block energy charge. The effect of this change is to remove a great deal of incentive for large commercial and industrial customers to reduce demand. This could ultimately lead to decreased system load factor and the need for more generating capacity.

Q. Why is it important for the Company to send price signals to limit summer demand and improve system load factor?

A. PECo has been a summer peaking Company since 1958 and will continue to be a summer peaking Company in the foreseeable future. It is the increase in summer peak loads that results in the necessity to construct additional high cost production and transmission facilities. In order to minimize the need for additional capacity, it is important to send cost based price signals to the customers. Dr. Wirtshafter admitted in his testimony that such price signals are effective when he stated that "The non-manufacturing class is very likely to control their loads to conform to the rate signal conveyed by the proposed rate". If this is true (and I believe that it is), the requirements for future generating capacity will be reduced.

Contrary to Dr. Wirtshafter's view, it is beneficial to the Company and to the customers to improve system load factor. Improved system load factor results in better utilization of the facilities that have been installed to satisfy the demand requirements of the system; thus, the fixed costs of these facilities can be recovered from more units of consumption. Furthermore, until such time that the system load factor is so high that additional capacity is required solely for maintenance purposes, it is beneficial to continue to encourage the improvement of system load factor. With PECo's current system load factor of less than 60%, there is ample room for improvement in system load factor before additional capacity would be required for maintenance purposes.

Q. Can you quantify this decrease in incentive to reduce demand?

A. Yes. Under the Company's allocation method a Rate HT customer would save $22.67 for each kilowatt of demand reduction. Under the UP/UUC, OCA and PBUUG proposals, this incentive would be reduced to $13.60/kW, $14.32/kW and $14.87/kW, respectively.

Q. Are there any other disadvantages to an energy allocation of production plant?

A. Yes. It can be seen from the preceeding table that the end block price of the rate is considerably higher under the proposals of the intervenors than under PECo's proposal. This not only results in larger increases to high load factor customers that generally employ large numbers of people, but also creates revenue instability. This instability occurs due to the significantly larger portion of fixed costs that are recovered in the end block price.

Q. Mr. Oliver and Mr. Sterzinger do not agree with the Company' method of allocating distribution costs between those costs that are customer related and those that are demand related. Would you comment on the Company's method for allocating these costs?

A. Yes. First let me state that this issue was litigated extensively in the Company's last two electric rate cases (Docket Nos. R-842590 and R-822291), and the method used by the Company was found to be acceptable by the Commission. The minimum size method used by the Company is one of the two methods described in the NARUC <u>Cost Allocation Manual</u> referred to by Mr. Oliver. The claim by Mr. Oliver that the Company's method is inconsistent with this manual is incorrect. This manual states on page 59, "The minimum size method involves determining the minimum size pole, conductor, cable, transformer and service <u>currently being installed</u>. The average installed book cost for such facility is then determined and used to develop the customer component." (emphasis added). This quote precisely describes the method used by the Company.

Q. Mr. Oliver claims that since the NARUC Manual was published in 1973 new methods have been developed to classify distribution costs. Do you have any comments on this?

A. Yes. There has been nothing since 1973 that would indicate that there are better methods than the ones described in the NARUC Manual. Mr. Oliver refers to a Modified Zero Intercept Method that is not described in the NARUC Manual. This method was proposed and rejected in the Company's last two electric rate cases. This classifies all labor costs as customer related and all materials costs as demand related, and thereby makes the unrealistic and incorrect assumption that none of the physical costs of the distribution system vary with number of customers. Furthermore, contrary to Mr. Oliver's claim, the data to implement this method is not available, is not required for any other purpose and would require expensive and time consuming studies.

Q. Do you have other comments on Mr. Oliver's direct testimony relative to the split of distribution system costs?

A. Yes. For some reason Mr. Oliver shuns the development of the customer component of distribution plant based on "real world" conditions in favor of what he claims is "...necessarily a theoretical construct". This is contrary to the minimum size method described in the NARUC Manual and would be similar to pretending that a distribution system exists other than the one that is actually in place. Mr. Oliver then proposes another method to determine the customer and demand components of cost which he does not endorse himself when he states "Once again, I note that these recommendations for modifications to the Company's distribution system cost allocation in no way represent an endorsement of those methods or an acceptance of their appropriateness".

The adjustment made by Mr. Oliver, that he does endorse, is based on the subtraction of the per customer demands that he obtained from the smallest use stratum of a Company residential load survey. If Mr. Oliver had looked at the largest use stratum, he would have found that the highest single demand of any customer was approximately 25 kW. The lines to serve the customers used by Mr. Oliver and the 25 kW customer would be identical. This is a clear indication that the cost of these lines is a function of the number of customers rather than the demand.

Q. Mr. Sundermeir, do you have any comments with regard to Mr. Sterzinger's direct testimony on the subject of the allocation of distribution costs?

A. Yes. Mr. Sterzinger claims that no precise definition of the minimum size equipment or its cost has been given. This is not true. This information was provided in IR-OCA-7-8 and IR-OCA-21-8. In addition, Mr. Sterzinger and Mr. Oliver both over emphasize the importance of the judgment required to perform the minimum size study done by the Company. In most cases the quantity and cost of the minimum size equipment can clearly be determined by examination of property records data and by verification of current practices by transmission and distribution engineers.

Q. Mr. Sterzinger has testified (Transcript page 3770) that all costs in Accounts 360 to 368 should be demand related. Do you agree?

A. No. To agree with Mr. Sterzinger I would have to believe that the distribution facilities are in no way related to the number of customers served by the Company. This is clearly unreasonable. Accounts 360 to 368 include poles, wire, line transformers and other items which clearly vary by number of customers. This result also is contrary to the classification of distribution costs as shown in the <u>NARUC Cost Allocation Manual</u>. This manual shows that a customer component of cost is typically included in primary and secondary lines, line transformers and services. The cost of this equipment is included in Accounts 360 to 369.

Q. Mr. Sterzinger claims that the Rate R customer cost developed by the Company is $207.30 per year and that, based on his calculations, this is an overcharge of $159 per year. Is he correct?

A. No. First it must be recognized that although the total customer cost is $207.30, the Company has only filed for a customer charge of $57 ($4.75/month x 12). The justification for this charge was provided in response to DR-Staff-RSS-3. The customer costs that the Company is asking to recover are only those costs that are incurred at the customers' premises. Mr. Sterzinger goes several steps further by arbitrarily cutting the cost of service lines to the customer in half, deducting the entire cost of the maintenance of these services and deducting the expenses associated with customer installations. None of these adjustments are justifiable. Furthermore, Mr. Sterzinger does not account for the $41,022,500 of services and the expenses that he excludes. Although Mr. Sterzinger makes no recommendation for recovery of these costs, they would have to be recovered by increases in the energy prices.

Q. Mr. Sundermeir, do you have any comments on Appendix A in Mr. Sterzinger's direct testimony?

A. Yes. Mr. Sterzinger refers to a national survey conducted by Carolina Power and Light Company which showed that a great majority of the utilities classify distribution system costs using some form of the minimum system. This further supports the Company's use of this method. A subsequent and more comprehensive survey was conducted by

Duke Power Company. The following table shows a comparison of the range of the percent of customer related costs from the Duke Study to the values used by PECo. It can be seen that the values used by PECo are within the ranges found for other utilities.

| | Percent of Costs Classified As Customer Related | |
|---|---|---|
| Account | Duke Power Study | PECO |
| 360 | 0- 84% | 35.4% |
| 361 | 0- 72 | 0 |
| 362 | 0- 31 | 0 |
| 364 | 0-100 | 64.1 |
| 365 | 0- 87 | 86.5 |
| 366 | 0-100 | 88.3 |
| 367 | 0-100 | 86.1 |
| 368 | 0- 70 | 54.8 |
| 369 | 0-100 | 88.2 |

Q. Mr. Sundermeir, Mr. Sterzinger and Mr. Oliver both question your method of allocation of Account 454 - Rent From Electric Property. Is the method that you have used appropriate?

A. Yes. To put this issue in perspective, the revenue from rental of electric property is less than 0.5% of the total revenue in Exhibit WFS-1. As shown in response to DR-WFS9-CEPA(1/6/86), $5,384,000 of the $10,449,000 in this account can be directly attributable to the production or transmission function. For this reason, an A-1 allocation of these revenues is appropriate.

Q. Several witnesses have proposed changes to the rate design of Rates HT and PD. Are these proposals justified in your opinion?

A. No, they are not. In R.I.D. 438 the Commission directed the Company to design "HT and PD rates which will eliminate, to the extent reasonably possible, variations in rates of return from customers within those classes". In order to comply with this Order, the Company was required to design Rates HT and PD to track costs as closely as possible.

The cost to serve a given customer consists of three basic components. The first are those costs that are demand related, the second are those that are energy related and the third are those costs which are customer related. These costs are determined from the cost allocation study. The cost curves shown on page 47 through 61 of Exhibit WFS-1 are the composite effect of these three components. The customer component of cost does not vary with changes in hours use of demand. The energy component increases linearly with an increase in hours' use of demand. The demand component reflects the increase in coincidence factor as load factor increases.

This relationship between coincidence factor and load factor is expressed by the Bary curve, which is derived from actual customer data, and the relationship is not linear. The Bary curve gives appropriate recognition to the probability of the individual customer's peak load occurring at a time coincident with the class peak load and thereby more precisely recognizes cost responsibility. It is essential that this relationship be recognized in rate design in order to reflect the effect of diversity of customer loads within a rate class. In order to follow cost to serve, the energy prices must be determined by the slope of the composite cost curve in each of the energy price blocks. Any deviation from the prices calculated in this manner will result in a rate design that does not follow cost to serve. Stated differently, such a deviation will not properly allocate system demand costs to customers within Rate HT in a manner which recognizes the extent of the probability that such customers contribute to system demand levels. The various proposals to increase or decrease demand and energy charges proposed by opposing parties in this proceeding would produce such deviations and therefore should be rejected.

Moreover, the proposals to increase the HT and PD tail energy blocks would significantly jeopardize the Company's ability to recover the revenue requirement approved by the Commission. One of the principal functions of rate design is to establish rates which will allow the Company to recover from ratepayers the total revenue requirement approved by the Commission. Under PECo's proposed rates, the tail block of Rate HT and PD already contain substantial fixed costs which the Company will incur regardless of the level of kWh sold. Further increases in the tailblock would assign more fixed costs to this block and would further jeopardize revenue recovery.

Q. Mr. Figley on behalf of PBUUG and Dr. Feldman and Dr. Wirtshafter on behalf of UP/UUC have recommended that the demand ratchet be eliminated in Rates HT and PD. Do you have any comments on their recommendations?

A. Yes, but first I would like to comment on some of the assumptions and characterizations made by Dr. Feldman and Dr. Wirtshafter.

First, as pointed out to them in a previous electric rate case (Docket No. R-822291), their assumption that non-manufacturing customers are low load factor customers and manufacturing customers are high load factor customers is not supported by the facts. There are high load factor non-manufacturing customers such as supermarkets and hospitals and low load factor manufacturing customers such as those with single shift operations. The following table shows a comparison of the average hours' use of industrial and commercial customers based on 1984 data.

| | Average Hours' Use of Demand | |
|---|---|---|
| | Industrial | Commercial |
| Rate HT | | |
| June | 479 | 401 |
| July | 523 | 447 |
| August | 501 | 457 |
| September | 478 | 413 |

| | Average Hours' Use of Demand | |
|---|---|---|
| | Industrial | Commercial |
| June | 479 | 401 |
| Average Summer | 496 | 430 |
| January | 520 | 476 |
| Rate PD | | |
| June | 292 | 340 |
| July | 306 | 382 |
| August | 305 | 399 |
| September | 293 | 349 |
| Average Summer | 299 | 368 |
| January | 314 | 410 |

It can be seen that the load factors of the industrial Rate HT customers are only slightly higher than the commercial customers while the load factors of commercial customers on Rate PD are actually higher than the industrial customers.

To further emphasize this point, the University of Pennsylvania is a high load factor non-manufacturing customer. Due to high load factor, the revenue from the University of Pennsylvania under the rates proposed by Dr. Wirtshafter would be $672,000 higher than under the rates proposed by PECo.

Secondly, Dr. Wirtshafter characterizes the ratchet as being a penalty. The ratchet is designed to recover the costs from those customers that are causing demand costs to be incurred (those with summer peaking loads). Without the ratchet, the number of demand billing units would decrease, and the demand charge to all customers would increase; thus, all customers would be paying for those customers with high summer demands relative to their non-summer month demands.

Third, Dr. Wirtshafter implies that the ratchet only effects low and medium load factor customers. As Dr. Wirtshafter admitted during cross-examination, this is incorrect. The ratchet has nothing to do with monthly load factor, but is a function of the relationship between summer and winter demands. A high monthly load factor customer may be effected by the ratchet and a low monthly load factor customer may not.

Fourth, Dr. Wirtshafter states that the ratchet is unfair in that is only imposed on non-manufacturing customers. Again, this is not true. The ratchet is applicable to all customers on Rates HT and PD regardless of whether or not the customer is non-manufacturing or manufacturing.

Fifth, Dr. Wirtshafter states that the demand ratchet is not generally used by other utilities. This is not true. Every major electric utility in the state of Pennsylvania has a demand ratchet except one. Furthermore, a recent national survey conducted for the E.E.I. Rate Research Committee showed that 80 of the 92 utilities surveyed have demand ratchets and/or minimum contract demand billing provisions.

Sixth, Dr. Wirtshafter tries to develop an estimate of the ratchet revenue by assuming that the power factor adjustment is the same in the winter as it is in the summer and that, after adjustment for power factor, the difference between actual and billed demands is due to the demand ratchet. There is no basis for either of these assumptions. If for no other reason, the power factor of air cooling equipment used in the summer is less than the unity power factory of electric resistance space heating used in winter. In addition, the difference between actual and billed demands that Dr. Wirtshafter attributes solely to the demand ratchet would also be attributed to the minimum billing demand based on 40% of the maximum contract demand.

Seventh, Mr. Wirtshafter characterizes "typical manufacturing users" as having, in one example, 5,000 kW and 648 hours' use, and in another example, 40,000 kW and 710 hours' use. There are over 700 manufacturing customers on Rate HT and approximately 500 such customers on Rate PD. Of this number, only eight customers have demand and hours' use over 5,000 kW and 648 hours' use and only two of these eight have over 40,000 kW and 710 hours' use. The examples used by Dr. Wirtshafter can hardly be characterized as typical.

Eighth, Dr. Wirtshafter assumes that the fifteen minute demands used by six of the ten utilities, that he compares to PECo, would be the same as the thirty minute demands used by PECo. This assumption is not justified.

An analysis made by PECo of a large, high load factor industrial customer showed that fifteen minute demands were approximately 13% higher than thirty minute demands. It is likely that this differential would be greater for lower load factors customers.

Ninth, Dr. Feldman makes a comparison of the operating costs of commercial buildings in various cities. He states that Philadelphia is fifth behind New York, Wilmington, Hartford and Newark. He also states that this comparison does not take into account the rate increase proposed by the Company. He fails to point out that it also does not include the rate increases filed by the utilities that serve Hartford and Newark.

Tenth, Dr. Feldman and Dr. Wirtshafter make various comparisons of revenues on PECo's rate to the rates of other utilities. As Dr. Wirtshafter admitted during cross-examination, these comparisons are made using the present rates of other utilities and the rate that PECo proposes to be effective in June 1988. Furthermore, they do not include the proposed rates of at least four other utilities.

Eleventh, Dr. Wirtshafter used the rates of Consolidated Edison Company of New York to support his analysis of the effects of a 10 kW increase in summer demand. Dr. Feldman and Dr. Wirtshafter did not make any other comparisons using the rate of Consolidated Edison. They also do not include other large Northeastern utilities such as Long Island Lighting Company and Boston Edison.

Q. Mr. Sundermeir, have you examined the workpapers used by Dr. Feldman and Dr. Wirtshafter to support their comparison of other utilities to PECo?

A. Yes. I have made a preliminary examination of their workpapers; however, I did not make a more thorough examination due to the numerous errors that I found in the preliminary examination.

Q. Would you describe some of these errors?

A. Yes. Dr. Wirtshafter states in his direct testimony that the billing data that he used to calculate the bills of selected customers are from July of one year to June of the next and that the ratchet demands are based on the demand from the previous summer period. With this in mind, the following is a list of serious errors that I found for only one of the customers analyzed by Dr. Wirtshafter - the University of Pennsylvania.

1. He uses 1985 billing data for January through June and 1984 data from July through December except in September he used the September 1985 demand and the September 1984 energy use. He then based the ratchet demand for the months of January through May of 1985 on the September 1985 demand instead of the highest demand in the summer of 1984. This has a significant effect on the billing demand, since the ratchet demand should be 29,376 kW instead of the 32,141 kW used by Dr. Wirtshafter.

2. For Delmarva he based the ratchet demand for January through May of 1985 on the demands in June 1984 and July through September of 1983. He should have used all 1984 data.

3. The total revenue that he calculated based on Delmarva's rates did not include the Public Utility Tax that would be applicable to the University of Pennsylvania.

4. His calculation of the effect of a 10 kW increase in summer demand did not include any ratchet in the months of January to May for the calculations using Delmarva's rates.

5. As Dr. Wirtshafter admitted during cross-examination, he did not apply the 80% ratchet in any month for Atlantic Electric. He also did not include the kVar charge. He did include 82,500 kWh in the second energy block and excluded 82,500 kWh from the third energy block - both of these are wrong.

6. Dr. Wirtshafter provided a worksheet showing a comparison of the annual bills of twelve customers using the rates of ten utilities in addition to PECo. Dr. Wirtshafter stated that only three of these ten utilities have rates with demand ratchets - Duquesne Light, Metropolitan Edison and Delmarva. Dr. Wirtshafter admitted during cross-examination that a fourth utility, Atlantic Electric, also has a demand ratchet. In addition, to the four utilities that Dr.

Wirtshafter indicates have demand ratchets, Potomac Electric Power Company and Pennsylvania Electric have demand ratchets; therefore, six of the ten utilities selected by Dr. Wirtshafter have demand ratchets in their rate schedules.

7. Dr. Wirtshafter did not include any adjustment to reflect the fact that Duquesne uses the sum of the maximum demand at each meter location instead of the conjunctive billing used by PECo.

8. Public Service of New Jersey has a separate demand charge for the maximum demands that occur in on-peak, intermediate and off-peak periods. Dr. Wirtshafter incorrectly divided the on-peak demand into three pieces instead of using the maximum demand in each of the three periods. His method seriously understates the demand charge.

Q. Did Dr. Wirtshafter and Dr. Feldman make any errors with customers that they analyzed other than the University of Pennsylvania?

A. Yes. I have looked at some of the other customers that they analyzed and found that they made many mistakes that are similar to those made with the University of Pennsylvania. In addition, the most significant mistake was the inclusion of demand adjusted for power factor when calculating bills using PECo rates. The higher demands resulting from the power factor adjustment were used even though Dr. Wirtshafter states in his testimony that stardard power factors were used and that PECo's billing demands were adjusted to reflect standard power factor. No such adjustment was made when calculating bills using PECo rates; however, they did make this adjustment when calculating bills using the rates of other utilities.

Q. Mr. Figley states in his direct testimony that the demand ratchet was introduced by the Company seven or eight years ago. Is he correct?

A. No. The 80% ratchet that is in the present and proposed tariffs has been in effect since March 1977; however, the ratchet has been in effect since August 1969.

Q. Mr. Figley claims that the fact that the customer's individual peak does not occur at the same time as the system peak has some effect on the validity of the demand ratchet, that the ratchet no longer serves a useful purpose and that it encourages customers to "squander" energy. Would you comment on these issues?

A. Yes. As I shall explain later, the benefit of the demand ratchet is not dependent on the customer's individual peak occurring at the same time as the Company's system peak. The fact that the customer's individual peak may be higher than the contribution to the system peak is taken into account when developing the ratchet percentage. Mr. Figley's argument that the importance of a demand price signal has diminished flies in the face of reality. With the higher capital costs of all methods of generation, it is more important than ever to send appropriate price signals to customers so that future generation capacity needs can be minimized. Finally, Mr. Figley's claims that the ratchet encourages customers to squander energy seems highly unlikely. Using Mr. Figley's illustration, under the Company proposed rates, each kilowatthour that a 280 hours' use cutomer wastes up to 300 hours' use will cost the customer 6.68¢/kWh. For a 1,000 kW customer, this wasteful use of energy would cost the customer $1,336. In addition, each kilowatthour that the customer squanders over 300 hours' use will cost 3.75¢/kWh. It seems unlikely that a customer would squander energy when the only effect is to increase the bill.

Q. Mr. Sundermeir, could you briefly explain the cost justification for the ratchet?

A. Yes. It must be understood that the annual demand related costs are recovered by monthly rate schedules. If a customer adds load only in the summer, the revenue collected from the customer in the summer will not fully recover the cost; therefore, without the demand ratchet this cost would have to be recovered from ratepayers who are not causing the cost. Let me illustrate by using data given in Exhibit WFS-1. As shown on page 39, the annual four-peak demand requirement for Rate HT is $366.73 kW. A high estimate of the ratio of the customers individual demand to the contribution to peak can be obtained by dividing the sum of the individual customers maximum demands (2,925,859 kW, page 66) by the contribution to system peak (2,135,188 kW, page 39). This ratio is 1.37 kW. Under the Company's proposed rates, a kW increase in billing demand adds $22.67 to the customer's bill. If a customer adds a kW at the time of the system peak, the Company would recover $31.06/kW ($22.67 x 1.37). If this additional billing demand only occurs in the four summer months the Company would recover $124.24 ($31.06/kW x 4) of the total cost of $366.73. By using the ratchet, the Company is assured of recovering an additional $198.78 ($31.06 x 8 months x 80% ratchet) or a total of $323.02 ($124.24 + 198.78). Even with the ratchet the revenue collection is less than the increase in cost.

Q. Mr. Sundermeir, Dr. Bloom on behalf of PAIEUG, has indicated that he supports the Company's cost to serve study but only after it has been adjusted to reflect different weather conditions than those that actually occurred on the peak days in 1984. Do you agree with Dr. Bloom?

A. No. It must be realized that the demands developed in 1984 are not used directly to allocate costs in the test year ended June 30, 1986. The data from 1984 that are used in the cost study are the ratios of the 1984 demands to the 1984 annual sales. These ratios are applied to the weather normalized sales in the test year to obtain the demands that are used in the cost study. Since ratios, rather than absolute values of demand are used, I do not believe that such adjustments are necessary; however, if such adjustments are deemed to be appropriate Dr. Bloom has not gone far enough.

Q. Would you explain your last statement?

A. Yes. Since the ratio of demand to energy is used, it would be necessary to not only adjust demands as Dr. Bloom has done, but it would also be necessary to adjust annual energy sales in 1984 to normal weather conditions. Furthermore, Dr. Bloom has not made any weather adjustments to Rates HT or PD nor has he presented any evidence that his failure to adjust these rates is justified.

Q. Mr. Sundermeir, have you previously made any weather adjustments to cost studies used in prior rate cases and have proposals been made before to make such adjustments?

A. The answer to both questions is no. The Company has been using the four-peak cost allocation method in all rate cases since 1975. Since that time the average effective degree hours (EDH) has ranged from a low of 133 (in both 1976 and 1984) to a high of 238 in 1980. The Commission has accepted the Company's cost studies, without weather adjustment, during that entire period.

Q. Dr. Bloom has also stated that the Rate HT A-1 demand allocation factor is overstated by 32,539 kW because it includes the demands of those customers on the Supplemental Energy provision of the Night Service Rider and that the Rate HT revenue did not include any revenue for supplemental energy. Would you comment on Dr. Bloom's position on supplemental energy?

A. Yes. To put the change that Dr. Bloom is suggesting into perspective, the 32,539 kW (34,069 kW at point of generation) that he is proposing would change the A-1 allocation factor applicable to Rate HT from 0.41462 to 0.41090 [illegible] change of less than 1%. Furthermore, I believe that such change is not justified. The loads used to develop the A-1 schedule are the actual demands used by the various classes of service at the times of the system peaks. The Company actually supplies the demands of the supplemental energy customers except during those infrequent times when the PJM system is in an emergency generation situation. This did not occur at the time of the peak in any of the four summer months. When the customers on supplementary energy are interrupted, their demands will be excluded from Rate HT, and the cost of the capacity will be allocated to the classes of service that use the capacity. With regard to the revenue from supplemental energy not being included in Rate HT revenue, the supplemental energy sales are included in the total Rate HT sales in the budget. These sales were budgeted at the normal Rate HT service rate; therefore, if any revenue adjustment is justified, it would result in a reduction to Rate HT revenue.

Q. Mr. Sundermeir, Dr. Bloom claims that the Bary curve cannot be used to develop cost curves for commercial and industrial customers unless the cost allocation is done using the non-coincident peak method. Is he correct?

A. No. It must be understood that the Bary Curve is not used for cost allocation purposes, and it is not used to develop unit costs. The Bary curve is used to develop the demand related portion of the total cost curve. The cost curve is then used to determine the energy pricing of Rates HT and PD. Dr. Bloom is correct that the Bary curve is related to the non-coincident class peaks; however, this does not prevent the use of other cost allocation methods to determine the total demand revenue requirement. To use the Bary Curve it is only essential that the unit cost used to develop the cost curve must be calculated by dividing the total demand related revenue requirement by the non-coincident class peak.

Q. Dr. Bloom claims that the fact that the Rate HT and PD revenue curves are always above the cost curves shown in Exhibit WFS-1 is the result of the failure of the Company to use the non-coincident cost allocation method when using the Bary curve. Is he correct?

A. No. The purpose of the cost/revenue curves is to show the relationship between cost and revenue. I have done this for four selected size Rate HT customers. The revenue curve is the same curve that would be obtained if the customer was billed for exactly the same demand every month and then divided by twelve. This, of course, does not happen in the real world. Attachment WFS-1 shows a comparison of the cost/revenue curves for a 100 kW Rate HT customer (similar to page 47 of Exhibit WFS-1). This shows that if a customer is billed for 100 kW in each of the four summer months and 80 kW in the eight winter months, the revenue curve falls below the cost curve. Obviously, there are thousands of combinations of cost determinant demands to billing demands. The Company's rate design is such that the revenues follow the shape of the cost curve and satisfy the total revenue requirement.

Q. Do you have any other comments with regard to Dr. Bloom's testimony?

A. Yes. Dr. Bloom has a paradox in his testimony. He supports the use of the non-coincident class peak cost allocation method, but he also supports an allocation method using only summer demands. Non-coincident class peaks may or may not occur in the summer. In fact, for Rate R-H the non-coincident class peak will never occur in summer.

Q. Mr. Sundermeir, have you reviewed the direct testimony of Mr. Pollock on behalf of PAIEUG?

A. Yes. Mr. Pollock makes some of the same points as Dr. Bloom. He does, however, make several statements that are inaccurate. He claims that "A significant portion of service is provided on a curtailable basis..." (emphasis added). As stated in response to an earlier question, based on Dr. Bloom's estimate, the elimination of curtailable load from the Rate HT A-1 allocation results in a change of less than 1%. This could hardly be considered to be significant. Also, in response to one of the questions pertaining to Dr. Bloom's testimony, it was explained that, if anything, the Rate HT revenue is overstated due to supplemental energy. Mr. Pollock claims that the Rate HT revenue is understated. Finally, Mr. Pollock claims that the present high voltage discount for Rate HT customers only recognizes the transformation costs that PECo avoids and does not take into account demand and energy losses. The Company has never claimed that the high voltage discount is based on costs that the Company avoids. The discount is based on the additional cost the customer incurs to take delivery at 33 kV or higher instead of the minimum high tension voltage of 13.2 kV.

Q. Mr. Pollock recommends that the tail block energy price in Rate HT should be reduced from the 3.75¢/kWh proposed by the Company to 3.18¢/kWh. Do you have any comments on his recommendation?

A. Yes. Mr. Pollock has based his recommendation on calculations that he presents in Exhibit JP-1, Schedule 7. His calculation shows that the demand costs recovered in the tail block of the Company's proposed rates are 100% higher than the demand costs recovered in the tail block of the present rates. He claims that this is an excessive increase due to the fact that the proposed capacity charge is only 76% higher that the present capacity charge. Mr. Pollock's calculation of the 100% increase in the demand cost recovery in the last block is not correct.

Q. Would you explain why Mr. Pollock is not correct?

A. Yes. Mr. Pollock has based his demand cost recovery at present rates on a mixture of the present end block energy price and the costs that were submitted at the time of the rate filing in Docket No. R-842590. Based on the actual costs that were used in the determination of the 3.76¢/kWh end block price, the demand cost recovery in the end block at present rates is 0.714¢/kWh (3.760¢ - 3.046¢). Using this corrected demand cost, the increase in the demand cost recovery from present rates to proposed rates is 60.5% instead of the 100% calculated by Mr. Pollock. The 60.5% increase is less than the 76% increase in the demand charge.

Q. Mr. Sundermeir, could you compare the increase in the demand related costs recovered in the energy blocks as proposed by the Company to the increases proposed by Mr. Pollock?

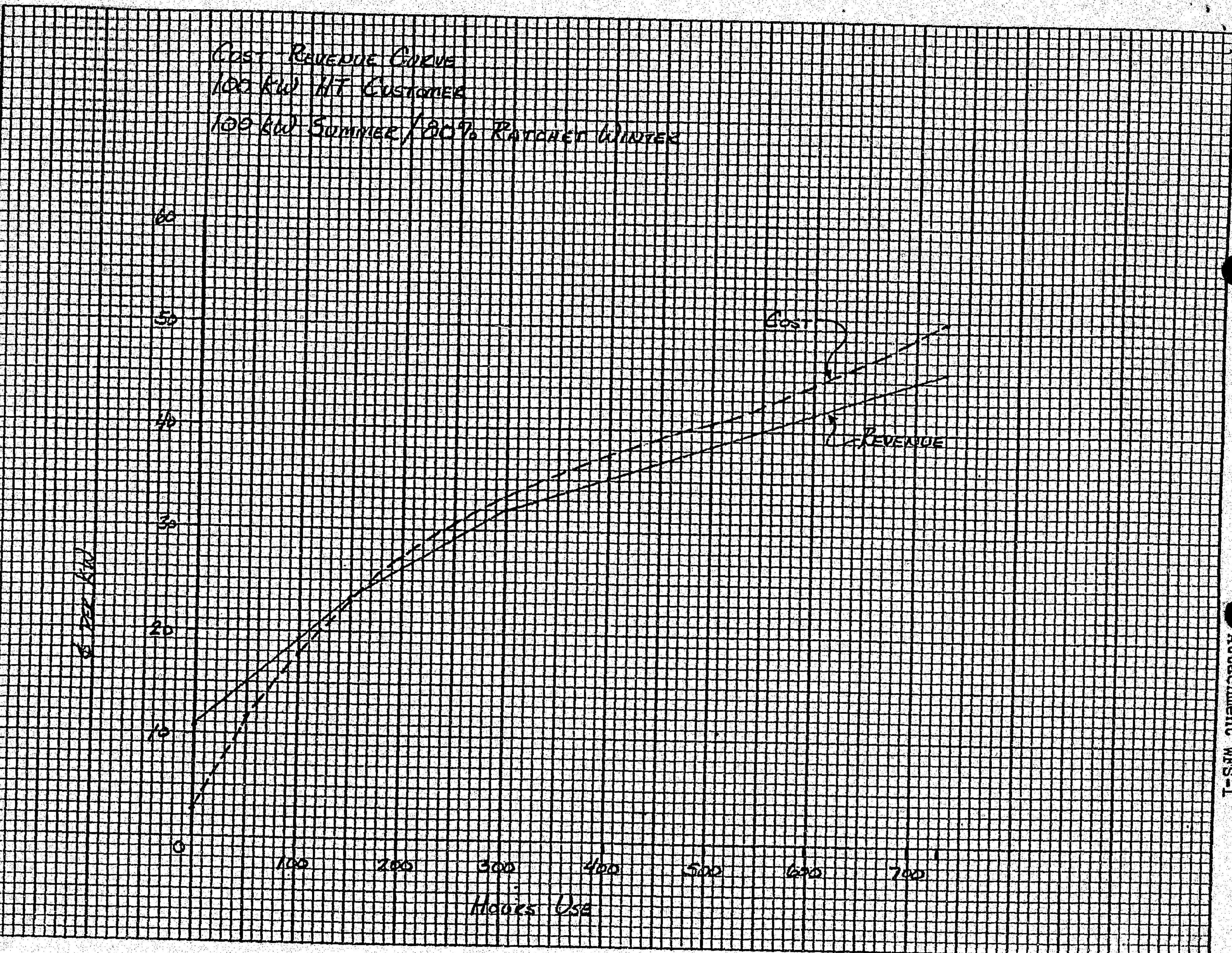
A. Yes. Under the rates proposed by the Company, the demand related costs recovered in each of the three energy blocks would increase, by approximately 60%. Under Mr. Pollock's proposal, the demand related costs in the first two energy blocks would also increase by approximately 60%; however, the demand costs recovered in the third energy block would <u>decrease</u> by approximately 20%.

Q. Mr. Sundermeir, Mr. Larson, on behalf of the Pennsylvania Food Merchants Association, supports the use of the Bary curve for the development of costs up to load factors of 40% to 55% (300 to 400 hours' use). He claims that the Bary curve is not applicable to higher load factors because there is little or no empirical information in the high load factor range and that the information that is available is not based on on-peak system demand. Is Mr. Larson correct?

A. No. Contrary to Mr. Larson's assumption, the Bary curve is plotted using actual customer data over a wide range of load factors that includes as many observations above the 40% to 55% load factor range as it does below that range; therefore, if Mr. Larson supports the use of the curve for load factors below 40% to 55%, there is no basis for not using the curve at higher load factors. Also, since the high load factor customers used to develop the Bary curve necessarily have off-peak use, Mr. Larson's claim that the Bary curve cannot be used to develop an end block price that includes some fixed costs is not valid.

Q. Mr. Sundermeir, does that conclude your rebuttal testimony?

A. Yes it does.




Attachment WFS-1

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SECRETARY'S OFFICE
Public Utility Commission

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Rebuttal Testimony and Exhibit of

JEFFRY POLLOCK

On Behalf of

Philadelphia Area Industrial Energy Users Group

(Allied Corporation, Fibers Division
Boeing Vertol Company
BP Oil, Inc.
The Budd Company
Liquid Air Corporation of North America
Lukens Steel Company
Nabisco Brands, Inc.
SDC (a Burroughs Company)
Smith Kline Beckman Corporation
Sun Refining and Marketing Company
3M Company)

and

United States Steel Corporation

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MAR 13 1986

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February, 1986
Project 4035

Drazen-Brubaker & Associates, Inc.
St. Louis, Missouri 63141-0110

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Rebuttal Testimony of

JEFFRY POLLOCK

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3M Company)

and

United States Steel Corporation

February, 1986
Project 4035

Drazen-Brubaker & Associates, Inc.
St. Louis, Missouri 63141-0110

PHILADELPHIA ELECTRIC COMPANY

before the

Pennsylvania Public Utility Commission

Docket No. R-850152

Rebuttal Testimony of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock, 605 Old Ballas Road, St. Louis, Missouri.

Q ARE YOU THE SAME JEFFRY POLLOCK WHO PREVIOUSLY TESTIFIED IN THIS DOCKET ON BEHALF OF THE PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP (PAIEUG) AND U. S. STEEL CORPORATION?

A Yes, I am.

Q WHAT ISSUES DO YOU ADDRESS IN YOUR REBUTTAL TESTIMONY?

A I shall address some of the specific cost-of-service and rate design proposals of the various Intervenors concerning:

(1) The classification and allocation of more than 60% of PECO's production and transmission capacity costs on the basis of "year-round" energy consumption,

(2) The substantial increase in the Rate HT tail block energy charge (to between 5.41¢ and 5.91¢ per kilowatthour), and

(3) The elimination of the 80% demand ratchet.

Q HAVE YOU PREPARED ANY EXHIBITS FOR SUBMISSION?
A Yes. I am sponsoring Exhibit JP-2 ( ), consisting of seventeen schedules.

CLASSIFICATION AND ALLOCATION OF PRODUCTION CAPACITY COSTS

Q VARIOUS WITNESSES--MR. STERZINGER ON BEHALF OF CEPA, MR. OLIVER ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE (OCA), MR. KING ON BEHALF OF THE PENNSYLVANIA BUSINESS UTILITY USERS GROUP (PBUUG) AND DR. WIRTSHAFTER ON BEHALF OF THE UTILITY USERS COMMITTEE/UNIVERSITY OF PENNSYLVANIA (UUC/UP)--HAVE RECOMMENDED THAT A SUBSTANTIAL PORTION OF PRODUCTION CAPACITY COSTS IS ENERGY-RELATED. THEREFORE, THESE COSTS SHOULD BE ALLOCATED ON THE BASIS OF YEAR-ROUND ENERGY CONSUMPTION. HAVE YOU REVIEWED THE TESTIMONY SUBMITTED BY THESE PARTICULAR WITNESSES?
A Yes, I have.

Q WHAT IS YOUR POSITION CONCERNING THE CLASSIFICATION AND ALLOCATION OF PRODUCTION CAPACITY COSTS?
A My position is that production capacity costs are demand-related, and they should be allocated to classes based on the revised four coincident peak demands quantified by Dr. Bloom. A demand-based classification and allocation is more consistent with (and reflective) of the principle of cost-causation than is a classification where allocation is primarily on "year-round" energy consumption. ("Year-round" energy consumption refers to the demands in each of

the 8,760 hours in a typical year.)

Q DID ANY OF THE OTHER WITNESSES PROPOSING AN ENERGY-BASED CLASSIFICATION AND ALLOCATION OF PRODUCTION CAPACITY COSTS JUSTIFY THEIR RECOMMENDATION BASED ON THE PRINCIPLE OF COST-CAUSATION?

A No, they did not. The term cost-causation seldom appears in the testimony of these four witnesses. In fact, the recommendations are based primarily on "Cost-Benefits" theory, rather than on the generally-accepted principle of cost-causation (Testimony of George J. Sterzinger, Page 8; Testimony of Bruce R. Oliver, Page 14; Testimony of Charles W. King, Page 26; Testimony of Dr. Robert Wirtshafter, Page 2).

Second, the recommended adjustments to the cost-of-service study were based on an incomplete analysis. (Dr. Wirtshafter's recommendations are not supported by any specific analysis.) Although each witness invokes the simplified theory of utility system planning (whereby planners make explicit trade-offs between production capital costs and operating costs), their specific recommendations affected only the capital cost side of the ledger. As described later in my rebuttal testimony, no attempt was made to apply the same costing theory to allocate operating costs (of which fuel and purchased power expense is a primary component). If capital cost allocation is to be based on a simplified theory of utility system planning, then there must be a symmetrical allocation of fuel and purchased power costs. That is, if a high load factor class is to be allocated above-average capital cost (because it is more economical to serve this class with base load generating capacity), then it follows that this class should be allocated below-average fuel costs (because base load units typically have lower fuel costs than do other types of generating capacity).

Q ARE THERE ANY OTHER PROBLEMS WITH THE COST ALLOCATION RECOMMENDATIONS SPONSORED BY THESE FOUR INTERVENORS?

A Yes, there are. In at least two instances, these witnesses have taken contradictory positions on other issues. For example, Mr. King's position on the recovery of Limerick No. 1 capital costs over time contradicts his recommendation that 89% of Limerick Unit No. 1 capacity costs are energy-related. Similarly, Mr. Oliver's and Mr. Sterzinger's contentions that PECO's classification and allocation of distribution costs result in "double-counting" also apply to their recommendation that the peak and average method be used to allocate production capacity costs.

Finally, there are potentially serious consequences resulting from classifying a substantial portion of production capacity costs to energy. Among them are: (1) worsening of system load factor, (2) income stability, and (3) reducing the incentive to shift or increase power and energy consumption to off-peak periods.

Q PLEASE DEFINE THE TERM "PRODUCTION CAPACITY COSTS"?

A Production capacity costs are related to the specific production facilities of a utility. The cost components include:

(1) Return on investment.

(2) Fixed operation and maintenance expenses (which do not vary with the amount of energy generated and sold).

(3) Depreciation expense.

(4) Related taxes (ad valorem, income, etc.).

Q WHAT IS THE BASIS FOR YOUR POSITION THAT ALL PRODUCTION CAPACITY COSTS SHOULD BE CLASSIFIED AND ALLOCATED RELATIVE TO THE INSTANTANEOUS DEMAND?

A First, generating units (and transmission facilities, as well) are rated in terms of the maximum amount of demand that can safely be imposed on them. They are not rated in terms of average annual demand; that is, the amount of energy produced divided by the number of hours in a year. Thus, in order to provide reliable service, there must be sufficient capacity available to meet the maximum expected (instantaneous) demand plus an allowance for reserves, at any point in time.

Second, most privately-owned utilities in this country must secure the approval of one or more commissions or other regulatory authorities before beginning the construction of a large, base load plant. Rarely, if ever, does a utility request such authorization without producing a demand forecast showing the need for additional capacity based on an increase in projected load. Furthermore, it is doubtful that any regulatory authority has ever authorized the commencement of such construction without being convinced that it was required to meet reasonably anticipated demands.

Looking at this proposition in another way, it would follow that, if it is fuel cost savings that are the driving force behind the construction of base load plants, then once approved, a base load plant would never be postponed or canceled simply because of a change in the utility's load forecast. Certainly, other factors could cause delays or cancellations despite potential fuel savings. A review of currently projected coal and nuclear units, however, shows that, in fact, utilities are postponing large amounts of such base load capacity due to reduced load forecasts (U. S. Department of Energy, Energy Information Administration, "Inventory of Power Plants," Washington, D. C., 1980).

Q BUT ISN'T IT APPROPRIATE TO CLASSIFY A PORTION OF PRODUCTION CAPITAL COSTS TO ENERGY BECAUSE OF THE FUEL SAVINGS RESULTING FROM THE INSTALLATION OF MODERN BASE LOAD PLANTS?

A As a general proposition, no. One must be careful to distinguish between cause and effect. Although the effect of operating a base load unit at a high capacity factor is to produce fuel cost savings (relative to the costs which would have been incurred by operating a peaker plant at the same level), the factor which caused the utility to construct the base load plant was the need to meet projected demands reliably. To suggest otherwise would be an oversimplification of the planning process.

INCOMPLETE ANALYSIS

Q DURING THEIR CROSS-EXAMINATION, MESSRS. OLIVER AND STERZINGER CONCEDED THAT, ALTHOUGH THEY USED THE PEAK AND AVERAGE METHOD TO ALLOCATE PRODUCTION AND TRANSMISSION CAPACITY COSTS, FUEL COSTS WERE ALLOCATED IN THE TRADITIONAL MANNER--RELATIVE TO CLASS ENERGY REQUIREMENTS AT THE GENERATION LEVEL. IN YOUR OPINION, DOES THIS COST ALLOCATION TECHNIQUE COMPLETELY REFLECT THE PRODUCTION COST TRADE-OFFS UPON WHICH THEIR RESPECTIVE RECOMMENDATIONS ARE BASED?

A No, it does not. Assuming that it is also appropriate to recognize the capital and fuel cost trade-offs (in addition to peak demand) in a cost-of-service study, then one would expect to find similar trade-offs when analyzing the results of the study for individual customer classes. In other words, those customer classes having relatively low load factors would be allocated below-average fixed costs, but above-average variable costs. This would parallel the relatively low fixed costs and high variable costs of peaking units which would be the more economical choice to serve loads of shorter duration (i.e., lower load factor). By contrast, high load factor classes would be allocated above-average fixed costs and below-average variable costs to parallel the high fixed cost, low variable cost characteristic of base load units which are designed to more economically serve loads of longer duration (i.e., higher load factor).

As shown in Exhibit JP-2 ( ), Schedule 1, the peak and average method fails to live up to these expectations. Specifically, the high tension (Rate HT) class (which has a relatively high load factor) is assigned above-average capital costs but only average fuel costs--contrary to expectations.

Q WHAT IS THE BASIS FOR YOUR EXPECTATION THAT HIGH LOAD FACTOR CUSTOMERS SHOULD BE ALLOCATED BELOW-AVERAGE VARIABLE COSTS?

A This can be demonstrated by using a "lowest cost system" (LCS) model. The LCS is the generation system that explicitly takes into account the trade-offs between capital costs and variable costs of different technologies, in order to minimize the total fixed and variable costs of serving a given load. In other words, the LCS explicitly reflects the capital substitution effect. To demonstrate this effect, I have constructed an LCS for the total PECO system and for a hypothetical high load factor class. By comparing the per unit fixed and variable costs, it is possible to demonstrate that the recognition of the production cost trade-off should result in allocating below-average variable costs to a high load factor class.

Q HOW WAS THE "LOWEST COST SYSTEM" DEVELOPED?

A We first have to determine the cross-over (or "threshold") point at which base load capacity becomes more economical than peaking capacity. Using data from the <u>EPRI Technology Assessment Guide</u>, the representative figures are:

| | Annual Fixed Cost/kW | Variable Cost/kWh |
|---|---|---|
| Base | $243.38 | $.01669 |
| Peaking | 47.60 | .15799 |

These amounts are derived in Exhibit JP-2 (   ), Schedule 2.

The base plant has a higher fixed cost per kW, but a lower variable cost per kWh as compared to the peaking plant. At 1,386 hours of usage, the two types of capacity have the same total production cost:

| | | |
|---|---|---|
| Base: | \$ 243.38 + (1,386)(\$.01669) | = \$267 |
| Peaking: | \$ 47.60 + (1,386)(\$.15799) | = \$267 |

If a unit is to be run for less than 1,386 hours, the lower "up-front" fixed cost of the peaking plant makes this type more economical. If the plant is to be run more than 1,386 hours per year, the base load unit is more economical.

Q WHAT IS THE NEXT STEP FOR DERIVING THE LCS?

A The next step is to look at the load duration curve and determine the optimal amount of base and peaking capacity. Exhibit JP-2 (   ), Schedules 3 and 4, respectively, show a representative load duration curve for the total PECO system and for the hypothetical high load factor class. On each curve, I have marked the point at which the load duration reaches 1,386 hours. For example, the total PECO load is most economically served by 4,128 MW of base capacity--which will be operated for more than 1,386 hours per year--and 1,797 MW of peaking capacity--which will be operated for less than 1,386 hours per year. The corresponding capacity mix for the high load factor class is 2,034 MW of base load capacity and 404 MW of peaking capacity. These amounts are summarized in Exhibit JP-2 (    ), Schedule 5. This schedule demonstrates that, on a "stand-alone" basis, there is a significant difference in the capacity mix between a high load factor class and the total PECO system.

Q IF THERE ARE DIFFERENT PROPORTIONS OF BASE LOAD AND PEAKING <u>CAPACITY</u> FOR A HIGH LOAD FACTOR CLASS, WOULD THERE ALSO BE DIFFERENT PROPORTIONS OF BASE LOAD AND PEAKING ENERGY?

A Yes. Exhibit JP-2 (    ), Schedule 6, shows the base load and peaking energy generation for the total PECO system and for the high load factor class. Although the differences in the generation mix are not as pronounced (as in the case of the capacity mix), Exhibit JP-2 (    ), Schedule 7, confirms that the per unit variable cost for the high load factor class (of 1.825¢) is about 5% below the PECO system average variable cost (of 1.918¢).

Thus, the LCS analysis confirms the earlier expectation that a proper reflection of capital and fuel cost trade-offs should result in allocating a below-average variable cost to a high load factor customer class.

Q WHAT IS THE SIGNIFICANCE OF THE 1,386-HOUR BREAK-EVEN THRESHOLD?

A The significance of the break-even threshold is that, once the threshold is reached, additional energy use (and the fuel cost savings resulting therefrom) has no impact on the investment decision. Therefore, load duration may influence investment decisions, but only up to a point. It would be logically incorrect to jump from this to a method in which production capacity costs are allocated to all 8,760 hours of the year. Yet, this is precisely the assumption upon which both Messrs. Sterzinger, Oliver and King base their recommendations. Clearly, no capital costs should be allocated to those hours beyond the break-even threshold. Because they recommend allocating capital costs to all hours, these witnesses have mischaracterized the system planning process.

Q WOULD THE RESULTS OF THE LCS ANALYSIS HAVE BEEN MUCH DIFFERENT IF THE ANALYSIS WERE DERIVED FROM PECO-SPECIFIC, RATHER THAN EPRI, COST DATA?

A No, they would not. For example, based on PECO's 1980 analysis of projected Limerick capital costs, projected first-year fuel and operation and maintenance expenses, and escalation rates, the break-even point between would have been 1,303 hours. Irrespective of the specific break-even point, it is axiomatic that the optimal capacity and energy mix differs according to load shape. Thus, appropriate recognition of system planning considerations should result in differences in per unit capacity and energy costs allocated to each customer class.

Q CAN YOU PROVIDE AN EXAMPLE TO DEMONSTRATE THAT, UNDER A COST-CAUSATION APPROACH, CAPITAL COSTS SHOULD NOT BE ALLOCATED TO ALL 8,760 HOURS?

A Yes, I can. Messrs. Sterzinger, Oliver and King each argue that, if a utility only had to meet its peak demand, then it would need to install only peaking units (Sterzinger Testimony, Page 7; Oliver Testimony, Page 11; King Testimony, Page 25). Based on the LCS analysis described earlier, the cost to serve the on-peak period (defined as the area under the load duration curve to the left of the break-even point) would be \$1,270 million, as shown in the chart below:

Chart 1

Total On-Peak* Production Cost Assuming that Service Were Supplied Entirely from Peaker Units

| | |
|---|---|
| Capital Cost | = System Peak x Cp |
| | = 5,925 MW x \$47.60/kW |
| | = \$282.0 Million |
| Variable Cost | = On-Peak Energy x Vp |
| | = 6,252,600 MWh x \$.15799/kWh |
| | = \$987.8 Million |
| Total On-Peak Cost | = \$1,270 Million |

Where: Cp = Capital Costs of a Peaking Unit
Vp = Variable Costs of a Peaking Unit

*Highest 1,386 hours of load.

However, this is equivalent to the total production capital cost (both base load and peaking) and the on-peak variable cost derived in the LCS model in Schedule 7 and in the chart below:

Chart 2

Total On-Peak* Production Cost
Derived from LCS Model

| | | |
|---|---|---|
| Capital Cost: | | |
| Peak-Related | = 5,925 MW x $47.60/kW | = $ 282 Million |
| LDC-Related | = 4,128 MW x ($243.38 - $47.60) | = $ 808 Million |
| Total Capital Cost | | = $1,090 Million |
| Variable: | | |
| Peaker | = 531,192 MWh x $.15799/kWh | = $ 84 Million |
| Base Load | = 5,721,408 MWh** x .01669/kWh | = $ 96 Million |
| Total Variable Cost | | = $ 180 Million |
| Total On-Peak Production Cost | | = $1,270 Million |

*Highest 1,386 hours of load.
**4,128 MW x 1,386 hours.

Thus, allocating production capital costs to the off-peak hours would, by definition, understate the cost of providing service during the on-peak hours and overstate the off-peak cost of service.

Q PLEASE SUMMARIZE YOUR CRITICISM OF THE ANALYSIS OF MESSRS. STERZINGER, OLIVER, KING AND DR. WIRTSHAFTER?

A These witnesses have failed to demonstrate that their respective allocation proposals are consistent with the principle of cost-causation. The earlier examples demonstrate that the incorporation of production costing trade-offs into the cost analysis <u>does not</u> support their contentions that year-round energy consumption causes a utility to incur production capital costs.

Further, Mr. Oliver has presented no evidence to support applying the same procedure to allocate transmission capacity costs. Even if it were appropriate to recognize production costing trade-offs in a cost-of-service study, these same trade-offs are clearly invalid with respect to the transmission system.

## CONTRADICTORY POSITIONS

Q WHAT IS THE BASIS FOR YOUR CONTENTION THAT MR. KING'S RECOMMENDATION TO CLASSIFY ALMOST 90% OF LIMERICK CAPITAL COSTS TO ENERGY IS INCONSISTENT WITH HIS OTHER RECOMMENDATIONS?

A Mr. King's recommendation resulted from a simple comparison between the cost of a peaking unit ($396 per kW) to the cost of Limerick ($3,621 per kW)--i.e., one minus $396 divided by $3,621 equals 89.1%. However, in the first part of his testimony, Mr. King recommends that the Limerick capital cost recovery "be distributed more evenly over the life of the plant in a pattern more consistent with the incurrence of the benefits from the plant" (Testimony at Page 9). These positions are inconsistent. While Mr. King has recommended the use of a "benefits received" standard for recovering capital costs, his classification of Limerick capacity costs is based solely on the relative capital costs between a peaking unit and Limerick without considering the benefits received. If Mr. King had applied the same "benefits received" test for cost allocation purposes as he recommends for revenue requirement purposes, substantially more of the Limerick capital costs would have been classified to demand.

Q ARE YOU ADVOCATING THE USE OF A BENEFITS RECEIVED TEST TO DETERMINE

COST CLASSIFICATION?

A No, I am not, but neither is Mr. King (Testimony at Page 14). Mr. King recognizes that the determination of Limerick benefits is imprecise, subject to controversy and totally unpredictable. If applied to rate design, it could lead to wide variations in cost classification depending on the actual performance of the unit. If the unit failed to perform adequately, more of the cost would be classified to demand and vice-versa if the unit performed better than expected. The result would be a potentially unstable cost allocation process which, in turn, would send conflicting price signals to customers. Thus, a benefits received approach would not only be unworkable, but it would be contrary to generally-accepted rate-making practice, in my opinion.

Q DOES THE FACT THAT THE COST OF LIMERICK, IN RETROSPECT, TURNED OUT TO BE NEARLY TWELVE TIMES MORE EXPENSIVE THAN THE COST OF A PEAKING UNIT HAVE ANY RELEVANCE IN DETERMINING COST ALLOCATION AND RATE DESIGN ISSUES IN THIS DOCKET?

A No, it has no meaning or relevance whatsoever. The differences in cost that we now observe are a relatively recent phenomenon, resulting from a variety of factors that have little to do with the inherent economics of generating plants. For example, according to PECO's 1984 FERC Form 1 Report, the Peach Bottom Units were installed in 1974 and have a cost of about $442/kW, while the Croydon Peaking Units (which also became operational in 1974) have an installed cost of $122/kW. Thus, the cost differential (between nuclear base load and peaking units) used to be considerably lower than it is presently. In particular, many base load plants completed in recent years have shown higher capacity costs because of delays and cost overruns that had nothing to do with the objective of obtaining lower cost energy. Therefore, it is wrong to conclude that observed differences in capacity cost are the result of conscious decisions to spend more per kilowatt in order to achieve lower fuel costs.

Q TURNING NOW TO THE TESTIMONIES OF MESSRS. OLIVER AND STERZINGER, IS THERE ANY INCONSISTENCY BETWEEN THEIR RESPECTIVE RECOMMENDATIONS ON PRODUCTION CAPACITY COST ALLOCATION AND ANY OF THEIR OTHER COST ALLOCATION RECOMMENDATIONS?

A Yes, there is. Both Messrs. Oliver and Sterzinger contend that PECO's classification and allocation of distribution plant result in "double-counting." Both witnesses contend that double-counting occurs because the distribution demand allocators include the portions of customers' demand requirements that are fully satisfied by PECO's predominant minimum system facilities. Because the cost of the predominant minimum system facility determines the customer-related component of distribution costs, both witnesses contend that, to prevent double-counting, the demand fully satisfied by these facilities should be eliminated from the demand allocators. The validity of this argument, notwithstanding, it is obvious that the very same criticism can be applied to the peak and average method, which both witnesses recommend.

Q CAN YOU EXPLAIN WHY THERE IS DOUBLE-COUNTING UNDER THE PEAK AND AVERAGE METHOD?

A Yes. The peak and average method double-counts energy consumption. As illustrated in Exhibit JP-2 (  ), Schedule 8, double-counting occurs because:

(1) The energy component of fixed cost is allocated relative to year-round energy consumption or average demand, and

(2) The demand component of fixed cost is allocated based on the total coincident peak demand of each customer class.

The allocation of fixed costs based on year-round energy consumption is indicated by the shaded area at the bottom of the chart. If this investment is truly related to average demand, then the only reason that any utility would invest in any other type of investment would be to meet the demands <u>in excess of</u> the average demand satisfied from the energy-related investment. In other words, the production demand allocator should be modified by removing the average demand supplied from the energy-related investment.

Q HOW CAN THE DOUBLE-COUNTING PROBLEM BE ELIMINATED UNDER A PEAK AND AVERAGE ALLOCATION METHOD?

A The correction of the double-counting problem under the peak and average method is shown in Exhibit JP-2 (  ), Schedule 9. In order to correct the double-counting problem, it is necessary to subtract that portion of the four summer coincident peaks which is being supplied by the energy-related investment. This process is shown in Columns 4 and 5. Thus, the remaining, demand-related investment is allocated relative to excess demand; that is, the difference between the four coincident peak demands and the demand supplied by the energy-related plant.

## CONSEQUENCES OF CLASSIFYING A SUBSTANTIAL PORTION OF PRODUCTION CAPACITY COSTS TO ENERGY

Q ARE THERE ANY POTENTIAL CONSEQUENCES THAT WOULD RESULT FROM CLASSIFYING A PORTION OF PRODUCTION CAPACITY COSTS TO ENERGY?

A Yes. There are several possible consequences of classifying a portion of production capacity costs to energy, all of which militate against the principle of cost-minimization. With respect to interclass revenue allocations, the primary consequence is a worsening of system load factor. If some capacity costs are <u>classified</u> as energy costs, as well as being allocated on that basis, and if the demand and energy charges of rate schedules are determined on the basis of such classifications, then revenue and income instability are additional likely consequences.

Q HOW WOULD CLASSIFYING A PORTION OF PRODUCTION CAPACITY COSTS TO ENERGY RESULT IN A WORSENING OF SYSTEM LOAD FACTOR?

A Under such a classification procedure, any customer class can reduce its allocation of revenue responsibility by reducing its consumption even if its maximum demand and demand at the time of (monthly) system peak(s) are held constant. This is true because the class will be allocated both less variable costs and less fixed costs. To the extent that less variable costs are allocated to the class, this is a proper reflection of the fact that less total variable costs are incurred by the utility. A reduced allocation of fixed costs to a particular class, however, must be offset by an increased allocation of fixed costs to other classes because these costs are not avoided when customers reduce their level of consumption. This would follow even if the other classes did not exhibit any change in consumption or demand.

Over time the reward for reduced load factors inherent in this approach will lead to a reduction in system load factor relative to methods that classify all production capacity costs to demand. This occurs for two reasons:

(1) At any point in time, each individual class has an incentive to worsen its own load factor (based on its demand at the time of system peak) by reducing energy use, since this will reduce its allocation of capital costs, and

(2) Over time, growth of low load factor classes is encouraged vis-a-vis high load factor classes, which leads to a decreasing average system load factor.

In the short run, a lower system load factor means higher costs per kWh because fixed costs must be spread over fewer kWh. In the long run, a lower system load factor also means higher costs per kWh, because the plant that must be added to meet growth in sales at a low load factor exceeds the required additions if growth is occurring at a high load factor.

As an example of the short-run impact, consider a utility with a 1,000-MW load with annual fixed capital carrying costs of $100/kW. A reduction in load factor from 55% to 50% would increase the fixed costs per kWh of sales by 2 mills per kWh. This would add $1 per month to the electric bill of a residential customer consuming 500 kWh monthly and over $20,000 per month to the electric bill of a 20-MW industrial customer operating at an 80% load factor.

The long-term impact can be illustrated by considering a utility that must add 100 MW of capacity in order to meet growth in load at a 50% load factor. If that same growth had occurred at a 55% load factor, a 91-MW addition to capacity would be sufficient to meet the added load.

Q ARE THERE ANY OTHER POSSIBLE CONSEQUENCES RESULTING FROM CLASSIFYING A PORTION OF PRODUCTION CAPACITY COSTS TO ENERGY?

A Yes, there are two other potential consequences: (1) income stability and (2) a reduced incentive to shift or increase power and energy requirement to off-peak.

If, as a result of classifying some capacity costs to energy, these costs are recovered in the energy charges, and if the level of kilowatthour sales decreases (as often happens during an economic downturn), the utility's revenues will drop more than its costs, since fixed costs are being recovered from the energy or variable portion of the rate. On the other hand, a proper recognition of the differentiation between demand and energy costs would, under these circumstances, cause revenues to decline in closer correspondence to the decline in costs, because the energy charges basically would recover only those costs which do, in fact, vary with the number of kilowatthours sold.

Classification of a portion of capacity costs on the basis of energy reduces the savings to the customer that would result from increased use during off-peak hours. For example, if a customer were to increase his consumption during off-peak hours (without changing his demands or energy consumption during on-peak hours), this classification method would allocate more fixed costs to him than before, since the number of kilowatthours added during the off-peak period would increase the allocation of fixed costs, even though the system's total capacity and capacity-related costs had not increased. This reduces the savings that would be available to the customer as a result of adding load off-peak as opposed to on-peak, and therefore, provides less incentive to improve system load factor.

CORRECTIONS TO INTERVENOR COST-OF-SERVICE STUDIES

Q THUS FAR, YOU HAVE CRITICIZED THE SPECIFIC RECOMMENDATIONS OF MESSRS. STERZINGER, OLIVER, KING AND DR. WIRTSHAFTER CONCERNING THE ALLOCATION OF PRODUCTION CAPACITY COSTS. IN PARTICULAR, YOU CONTEND THAT THE COST ALLOCATION TECHNIQUES RECOMMENDED BY THESE

WITNESSES ARE FLAWED BECAUSE OF THE ABSENCE OF ANY FUEL SYMMETRY AND BECAUSE ENERGY CONSUMPTION IS DOUBLE-COUNTED. HAVE YOU DEVELOPED A REVISED COST-OF-SERVICE STUDY TO DEMONSTRATE TO THE ALJ AND TO THE COMMISSION THE IMPACT OF CORRECTING THE TWO MAJOR FLAWS?

A Yes, I have. The results of the revised cost-of-service study--corrected to recognize fuel symmetry and to eliminate double-counting--are summarized in Exhibit JP-2 (    ), Schedule 10. (It should be noted that the four coincident peak demands used in this revised study were based on the 1985 EDH analysis sponsored by Dr. Bloom.)

Q ARE THE RESULTS OF THIS REVISED COST-OF-SERVICE STUDY MATERIALLY DIFFERENT FROM THE FOUR COINCIDENT PEAK COST-OF-SERVICE STUDY WHICH FORM THE BASIS FOR YOUR VARIOUS RATE SPREAD AND RATE DESIGN RECOMMENDATIONS IN THIS DOCKET?

A No, at least for the major customer classes, the results of a peak and average study corrected for double-counting (Schedule 9) and with a fuel symmetry adjustment (Schedule 11) are quite comparable to the revised 4CP study (based on 1985 EDH), as shown in the chart below:

| | Index of Return | |
|---|---|---|
| | Corrected Peak and Average | 4CP |
| High Tension | 95 | 99 |
| Primary | 117 | 116 |
| Secondary | 130 | 126 |
| Residential | 87 | 84 |
| Street Lighting | 147 | 198 |
| AMTRAK | 114 | 119 |
| SEPTA | 133 | 144 |

Q COULD YOU PLEASE ELABORATE ON HOW THE FUEL SYMMETRY PROBLEM WAS CORRECTED IN THE REVISED COST-OF-SERVICE STUDY SHOWN IN EXHIBIT JP-2 ( ), SCHEDULE 10?

A Yes, I can. Exhibit JP-2 ( ), Schedule 11, sets forth an alternative allocation of fuel costs which is more consistent with system planning theory. Essentially, this alternative method identifies the fuel costs associated with base load units (Page 3) and allocates these costs relative to the base energy requirements of each customer class (Page 2, Column 4). The remaining fuel costs are allocated to those classes relative to the energy requirement met from the nonbase load units (Page 2, Column 6). Summing the nonbase costs and the base costs results in total fuel costs by customer class (Page 1, Column 3). The total fuel costs are then used to develop allocation factors (Page 1, Column 4) which are then input into the cost-of-service study.

## RATE HT TAIL BLOCK ENERGY CHARGE

Q HAVE YOU REVIEWED THE TESTIMONY OF MR. FIGLEY (ON BEHALF OF PBUUG) AND DR. WIRTSHAFTER CONCERNING THE RATE HT TAIL BLOCK ENERGY CHARGE?

A Yes, I have. A comparison between the PECO, PBUUG and UP/UUC proposed HT Rate designs is shown in Exhibit JP-2 ( ), Schedule 12. Both Mr. Figley and Dr. Wirtshafter are recommending substantially higher increases in the Rate HT tail block energy charge than PECO. Mr. Figley's recommendation of 5.41¢ would result in a 43.9% increase in the tail block, while Dr. Wirtshafter's recommendation of

5.91¢ would result in a 57.2% increase. By contrast, PECO is proposing a 0.3% decrease in the tail block energy charge.

Q WHAT IS THE BASIS FOR MR. FIGLEY'S AND DR. WIRTSHAFTER'S PROPOSED TAIL BLOCK ENERGY CHARGES?

A Because both witnesses used the same Bary curve analysis as did PECO in developing their recommendations, it may be concluded that the differences between their respective proposals and PECO's (and also PAIEUG et al's) result from their reclassification of up to 90% of Limerick Unit No. 1 capacity costs to energy. As I previously testified, this reclassification is inappropriate. Therefore, their respective Rate HT tail block energy charges are similarly inappropriate.

Q WHAT WOULD BE THE IMPACT OF A VERY HIGH RATE HT TAIL BLOCK ENERGY CHARGE ON THE MEMBERS OF PAIEUG ET AL?

A As shown in Exhibit JP-2 (     ), Schedule 13, the UP/UUC recommendation would have a substantial impact on the members of PAIEUG et al. Relative to PECO's proposed rate design, PAIEUG et al base rates would be increased by 37.5% instead of 24.1% under PECO's proposal--an increase of about 56% over the PECO proposal. Of course, one cannot take the fuel cost savings for granted as they depend on the performance of PECO's base load nuclear units. Consequently, the nonfuel percent increase is more meaningful. On this basis, the UP/UUC recommendation would increase PAIEUG et al nonfuel rates by 98.2% compared to 71.9% under PECO's proposal--an increase of about 37% over the PECO proposal. These differences would cost PAIEUG et al members nearly $15 million per year in addition to PECO's proposed increase.

Q WOULD HIGH LOAD FACTOR CUSTOMERS CONTINUE TO HAVE A STRONG INCENTIVE TO OPERATE AT A HIGH LOAD FACTOR UNDER THE PBUUG AND UP/UUC PROPOSALS?

A No, they would not. Exhibit JP-2 ( ), Schedule 14, sets forth the equivalent capacity and nonfuel energy charges as a function of hours' use under the PECO, PBUUG and UP/UUC rate design proposals. The equivalent capacity charges would be increased by a much smaller amount under the PBUUG and UP/UUC proposals for all customers, but particularly for those utilizing their demands for 300 hours' use and higher (which equates to a 41% or higher load factor). At this level, the equivalent capacity charge would increase by only 10% under the PBUUG proposal and, incredibly, by only 1% under the UP/UUC proposal. By contrast, the nonfuel energy charges would increase by nearly 300%, which is almost four times the proposed nonfuel percent increase to the Rate HT class. Thus, any notion of gradualism has been cast aside by the PBUUG and UP/UUC--contrary to generally-accepted rate design practice. This unprecedented "energy tilt," coupled with the elimination of the 80% demand ratchet, would substantially reduce the price differential between on and off-peak hours. Thus, high load factor customers do not have a strong incentive to remain high load factor. Because a similar tilt would occur even at lower load factors, these customers would not have an incentive to improve their load factors under the PBUUG and UP/UUC proposals. Further, by reducing the relative price of on-peak capacity and energy, these proposals would certainly discourage additional off-peak use and may even encourage on-peak use.

Q YOU PREVIOUSLY TESTIFIED THAT REVENUE AND INCOME INSTABILITY COULD RESULT FROM RATE DESIGNS IN WHICH A SUBSTANTIAL AMOUNT OF FIXED COSTS ARE RECOVERED THROUGH A KILOWATTHOUR CHARGE. WHAT IMPACT WOULD THE PBUUG AND UP/UUC PROPOSALS HAVE ON THE STABILITY OF RATE HT?

A Relative to PECO's proposal, the PBUUG and UP/UUC proposals would seriously exacerbate the instability problem of Rate HT. This is shown in Exhibit JP-2 (    ), Schedule 15.

Schedule 15 measures the percentage change in income resulting from a 2% change in kilowatthour consumption under both the PECO and UP/UUC proposed HT Rate designs. The results are summarized on Page 1. Page 2 shows the impact of a 2% reduction in kilowatthour consumption based on PECO's proposed rate design. Pages 3 and 4 show the same analysis based on the PAIEUG et al and UP/UUC recommended rate designs, respectively.

Referring to Schedule 15, Page 1, it is obvious that the UP/UUC proposed HT Rate design would be considerably less stable than either the PECO or PAIEUG et al rate designs.

Q IS IT REALISTIC THAT THE BILLING DEMANDS WOULD CHANGE IN THE SAME PROPORTION AS KILOWATTHOUR CONSUMPTION?

A No, it isn't. As long as a customer continues to operate at least one daytime shift, the demand imposed should not change from the level prior to the reduced consumption. Thus, Column 3 (no demand fluctuation) is the most realistic scenario.

## RATE HT DEMAND RATCHET

Q HAVE YOU REVIEWED THE TESTIMONY OF MR. FIGLEY AND DR. WIRTSHAFTER CONCERNING THEIR PROPOSALS TO ELIMINATE THE 80% DEMAND RATCHET?

A Yes, I have. Mr. Figley's primary criticisms are that:

(1) The ratchet fails to recognize diversity because an individual customer's peak demand may not be a valid representation of the impact (of that demand) on the growth in system peak, and

(2) It may discourage conservation because up to 80% of the maximum summer peak demand would be virtually cost free.

Dr. Wirtshafter's criticisms are that:

(1) The ratchet is obsolete,

(2) It overstates the cost of peaking capacity, and

(3) Ratchets are not generally used by other utilities.

None of these arguments are well-founded, and there appear to be some inconsistencies with other positions taken by these witnesses.

Q DOES THE RATCHET PROVISION FAIL TO RECOGNIZE DIVERSITY?

A No, it does not. Mr. Figley's argument would only be valid if the ratchet were 100% of the maximum summer demand, rather than 80%.

Because it is only an 80% demand ratchet, there is not a one-to-one correspondence between an individual customer's maximum summer demand and his contribution to PECO's summer peak demands. A customer having an 80% coincidence factor and a maximum summer peak demand of 1,250 kW would have a coincident demand of 1,000 kW. If this customer's billing demand during the nonsummer months were below 1,000 kW, he would continue to be billed for only his coincident demand. Thus, an 80% demand ratchet does recognize diversity, contrary to Mr. Figley's assertions.

Q ARE DEMAND RATCHETS INCONSISTENT WITH PROMOTING CONSERVATION?

A No. Demand ratchets provide a strong incentive for customers to conserve capacity and, therefore, utilize electricity more efficiently than would otherwise be the case absent a demand ratchet. This is especially important during the summer peak months because they determine the amount of capacity required by PECO to maintain nearly continuous service. By eliminating the ratchet, the incentive to conserve capacity would be severely diminished during the summer peak period. This could only hasten the day when PECO would have to install additional capacity to meet this increase in peak demand.

It is inconceivable that any businessman, manufacturer, university or other entity would deliberately increase his nonsummer demand to up to 80% of his maximum summer demand, particularly if this would mean an overall increase in on-peak energy consumption.

In an era of increased competition where there is considerable pressure to hold down costs, it would simply be imprudent for a customer to increase his overall cost of electricity just to take advantage of a lower per unit energy charge, unless, of course, the benefits of doing so would outweigh the cost. Nevertheless, this should not be an excuse to diminish the important pricing signal conveyed by the 80% demand ratchet; namely, to conserve capacity during the critical summer peak months.

Q MR. FIGLEY CITED A FEDERAL ENERGY REGULATORY COMMISSION (FERC) DECISION DISAPPROVING A 95% DEMAND RATCHET ON THE GROUNDS THAT IT WAS "INCOMPATIBLE WITH PUBLIC POLICY TOWARD ENERGY CONSERVATION. . . ." ET CETERA. HAVE YOU REVIEWED THE FERC DECISION TO WHICH HE REFERRED?

A No. Instead of providing the decision in Carolina Power & Light Company, Docket No. ER76-495, Mr. Figley supplied various Orders issued in a Connecticut Light and Power Company proceeding, Docket No. ER78-517. However, the quotation cited on Page 12 of Mr. Figley's testimony is referred to on Page 30 of the <u>Administrative Law Judge's Initial Decision on Rate Design</u> dated September 9, 1980.

Q IS THE FERC CASE REFERRED TO BY MR. FIGLEY DISTINGUISHABLE FROM THIS DOCKET?

A Yes, I believe it is. It is my understanding that the FERC has consistently eliminated demand ratchets because they were "patently incongruent" with the 12CP method of cost allocation. According to the Initial Decision,

> "Having employed that [the 12CP] method of cost allocation to determine the wholesale class responsibility, it makes little sense to allocate the burden of demand costs within the class by switching to a different method, and one which looks only to a single month's peak demand to do the job." (Page 30) [Information added]

On the very next page, the ALJ ordered that the 100% twelve-month demand ratchet for full requirement customers be eliminated to provide for the allocation of demand costs for those same customers in accordance with the 12CP method (see Page 31). Mr. Figley failed to mention that a 100% demand ratchet remained intact at least for the partial requirement customers of CL&P.

Because Mr. Figley has apparently adopted the 4CP method (and not the 12CP method) of allocating demand-related production and transmission capacity costs, it follows that the PECO case is clearly distinguishable from the FERC case. However, to be consistent, the billing demand provision should allocate demand costs within the Rate HT class in a similar manner as the 4CP method allocates these same costs to the class. This is precisely the reason why an 80% summer demand ratchet is appropriate for PECO.

Q PLEASE EXPLAIN.

A The 80% summer demand ratchet is nothing more than a tool to reallocate the Rate HT demand cost responsibility to those customers within the class who utilize relatively more demand during the summer peak months than at other times. To illustrate, let's assume that a particular class is allocated $1 million of demand cost responsibility and that the total coincident demand of this class is 1,000 MW. Further assume that this class can be subdivided into two customer groups--A and B. Both Customers A and B have a summer coincident demand of 500 MW. Therefore, as shown in Exhibit JP-2 (    ), Schedule 16, both Customers A and B would be responsible for 50% or $500,000 of demand costs.

Referring to Schedule 16, let's assume that Customer A is a nonseasonal user, while Customer B utilizes more capacity during the summer peak months. In this example, the total monthly maximum demand of Customers A and B would be 6,500 MW and 4,900 MW, respectively. Absent any demand ratchet, demand cost responsibility would be allocated relative to the monthly maximum demands. Consequently, Customer A would be responsible for about 57% (6,500 MW ÷ 11,400 MW) of demand costs, while Customer B would be responsible for only 43% (4,900 MW ÷ 11,400 MW) of demand costs. Thus, Customer A would overpay by about $70,000, while Customer B would underpay by about the same amount, both relative to their respective demand cost responsibility.

However, if an 80% demand ratchet were implemented, then Customer B's nonsummer billing demands would be 500 MW, rather than only 300 MW, and its total monthly maximum demand would be 6,500 MW--the same as Customer A. The result would be that both Customer A and Customer B would be allocated 50% of the total class demand cost responsibility which precisely matches the demand costs caused by each customer group.

Thus, contrary to Mr. Figley's and Dr. Wirtshafter's assertions, the demand ratchet does provide appropriate pricing signals and is certainly not obsolete if the rates within the Rate HT class are to closely track the demand cost responsibility imposed by individual customers within this class.

Q DR. WIRTSHAFTER CLAIMS (ON PAGE 19 OF HIS DIRECT TESTIMONY) THAT DEMAND RATCHETS ARE NOT GENERALLY USED BY OTHER UTILITIES, AND HE CITED ONLY TWO UTILITIES OF THE ELEVEN WHICH HE REVIEWED HAVING DEMAND RATCHETS. IS THAT AN ACCURATE ASSESSMENT?

A No, it is not. Besides Delmarva Power & Light and Metropolitan Edison, at least five of the remaining nine utilities have some type of billing demand ratchet. Exhibit JP-2 ( ), Schedule 17, summarizes the various provisions of each utility examined by Dr. Wirtshafter. In some cases, the ratchet is in the form of a minimum charge rather than an explicit adjustment to the monthly billing demand.

Q HOWEVER, AREN'T THE EXPLICIT AND IMPLICIT BILLING DEMAND RATCHETS OF THESE UTILITIES GENERALLY LOWER THAN FOR PECO?

A Yes, they are. However, several of these utilities having lower effective billing demand ratchets have seasonal demand charge differentials, time-of-use differentials and/or fifteen-minute demand intervals. Any of these characteristics would make it more costly to increase demand during the summer on-peak hours.

Q DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Rebuttal Exhibit of

JEFFRY POLLOCK

On Behalf of

Philadelphia Area Industrial Energy Users Group

(Allied Corporation, Fibers Division
Boeing-Vertol Company
BP Oil, Inc.
The Budd Company
Liquid Air Corporation of North America
Lukens Steel Company
Nabisco Brands, Inc.
SDC (a Burroughs Company)
Smith Kline Beckman Corporation
Sun Refining and Marketing Company
3M Company)

and

United States Steel Corporation

February, 1986
Project 4035

Drazen-Brubaker & Associates, Inc.
St. Louis, Missouri 63141-0110

PHILADELPHIA ELECTRIC COMPANY

Net Production Plant per Kilowatt of Peak Demand
and Fuel Cost per Kilowatthour Generated
Peak and Average Method
Year Ending June 30, 1986

| | | Net Production Plant | | | | Fuel and Purchased Power Expense | | | |
|---|---|---|---|---|---|---|---|---|---|
| Line | Customer Class | Amount (000) (1) | Peak Demand (kW) (2) | Per kW (3) | Index (4) | Amount (000) (5) | Energy Required (MWh) (6) | Per MWh (7) | Index (8) |
| 1 | High Tension | $2,351,756 | 2,143,078 | $1,097 | 111 | $262,569 | 13,320,283 | $19.71 | 100 |
| 2 | Primary | 463,359 | 469,779 | 986 | 99 | 48,471 | 2,458,984 | 19.71 | 100 |
| 3 | Secondary | 750,180 | 816,090 | 919 | 93 | 74,666 | 3,787,866 | 19.71 | 100 |
| 4 | Residential | 1,869,599 | 2,083,422 | 897 | 91 | 182,682 | 9,267,598 | 19.71 | 100 |
| 5 | Street Lighting | 21,376 | 297 | N/M | N/M | 3,703 | 187,844 | 19.71 | 100 |
| 6 | Other Utilities | 93,340 | 103,977 | 898 | 91 | 9,123 | 462,817 | 19.71 | 100 |
| 7 | Interdepartmental | 11,895 | 11,248 | 1,058 | 107 | 1,300 | 65,953 | 19.71 | 100 |
| 8 | SEPTA | 49,186 | 45,498 | 1,081 | 109 | 5,445 | 276,232 | 19.71 | 100 |
| 9 | AMTRAK | 74,210 | 60,844 | 1,220 | 123 | 8,751 | 443,926 | 19.71 | 100 |
| 10 | Total Company | $5,684,900 | 5,734,233 | $ 991 | 100 | $596,710 | 30,271,503 | $19.71 | 100 |

PHILADELPHIA ELECTRIC COMPANY

Comparison of Total Cost
Between Base Load and Peaking Units
(Dollar Amounts in Thousands)

| Line | Description | Base Load (1) | Peaker (2) |
|---|---|---|---|
| 1 | Fuel Type | Nuclear | Residual |
| 2 | Construction Cost ($/kW) | $1,150.00 | $235.00 |
| 3 | Levelized Carrying Charge | x 20.00% | x20.00% |
| | Annual Fixed Cost ($/kW): | | |
| 4 | Construction | $ 230.00 | $ 47.00 |
| 5 | O&M | 13.38 | 0.60 |
| 6 | Total | 243.38 | 47.60 |
| | Levelized Variable Costs: | | |
| 7 | Fuel ($/MWh) | 14.13 | 152.43 |
| 8 | Other O&M ($/MWh) | 2.56 | 5.56 |
| 9 | Total | $ 16.69 | $157.99 |
| 10 | Average Capacity Factor | 15.82% | 15.82% |
| 11 | Hours' Use | 1,386 | 1,386 |
| 12 | Capacity | 1,055 | 75 |
| 13 | Energy Generated (MWh) | 1,461,716 | 103,913 |
| 14 | Capital Cost | $ 256,766 | $ 3,570 |
| 15 | Variable Cost | 24,396 | 16,418 |
| 16 | Total Cost | $ 281,162 | $19,988 |
| 17 | Total Per Unit Cost | $ 192.35 | $192.35 |

Exhibit JP-2 ( )
Schedule 3

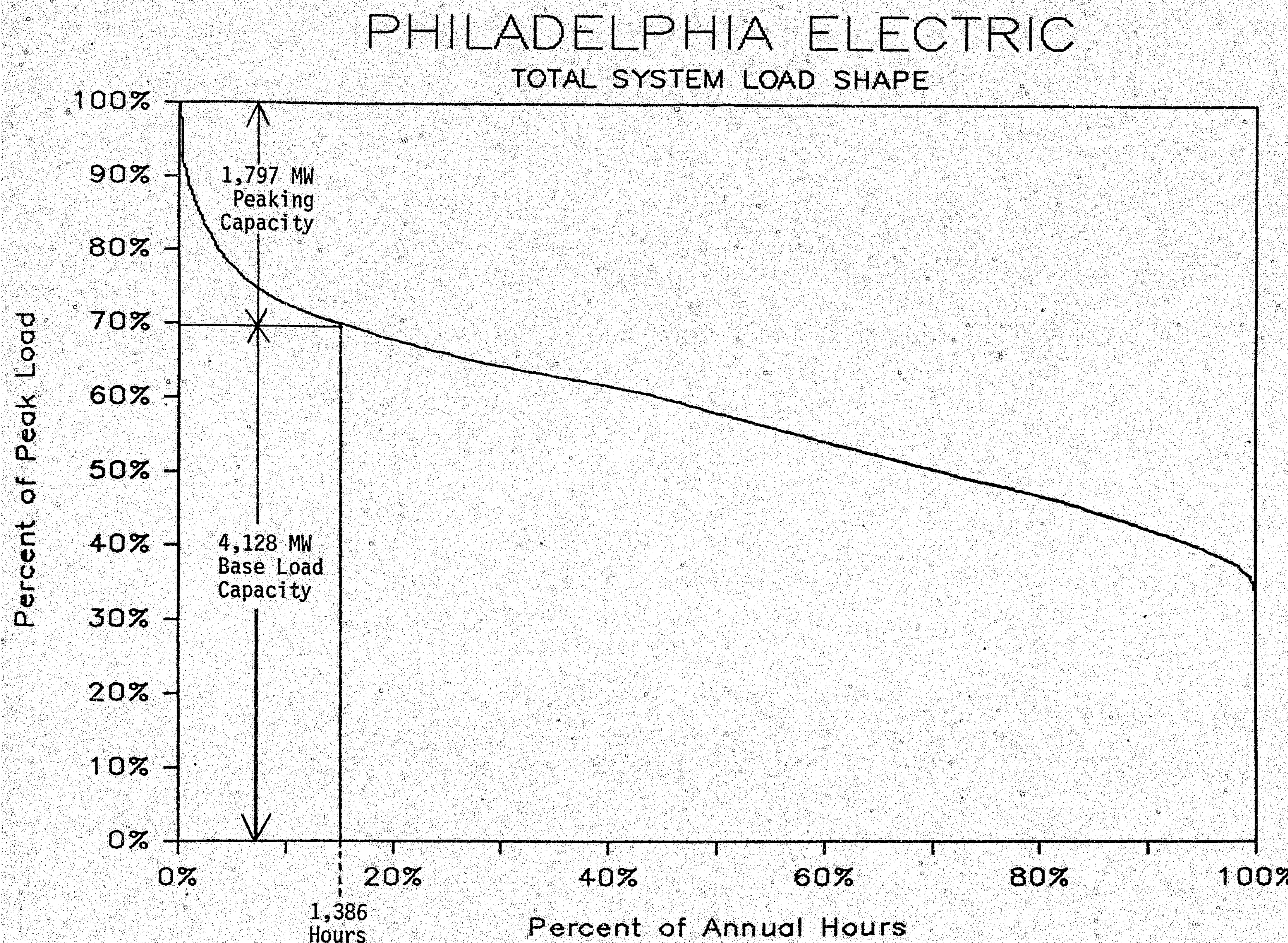


Exhibit JP-2 ( )
Schedule 3

Schedule 4

# PHILADELPHIA ELECTRIC

## HIGH LOAD FACTOR CLASS LOAD SHAPE

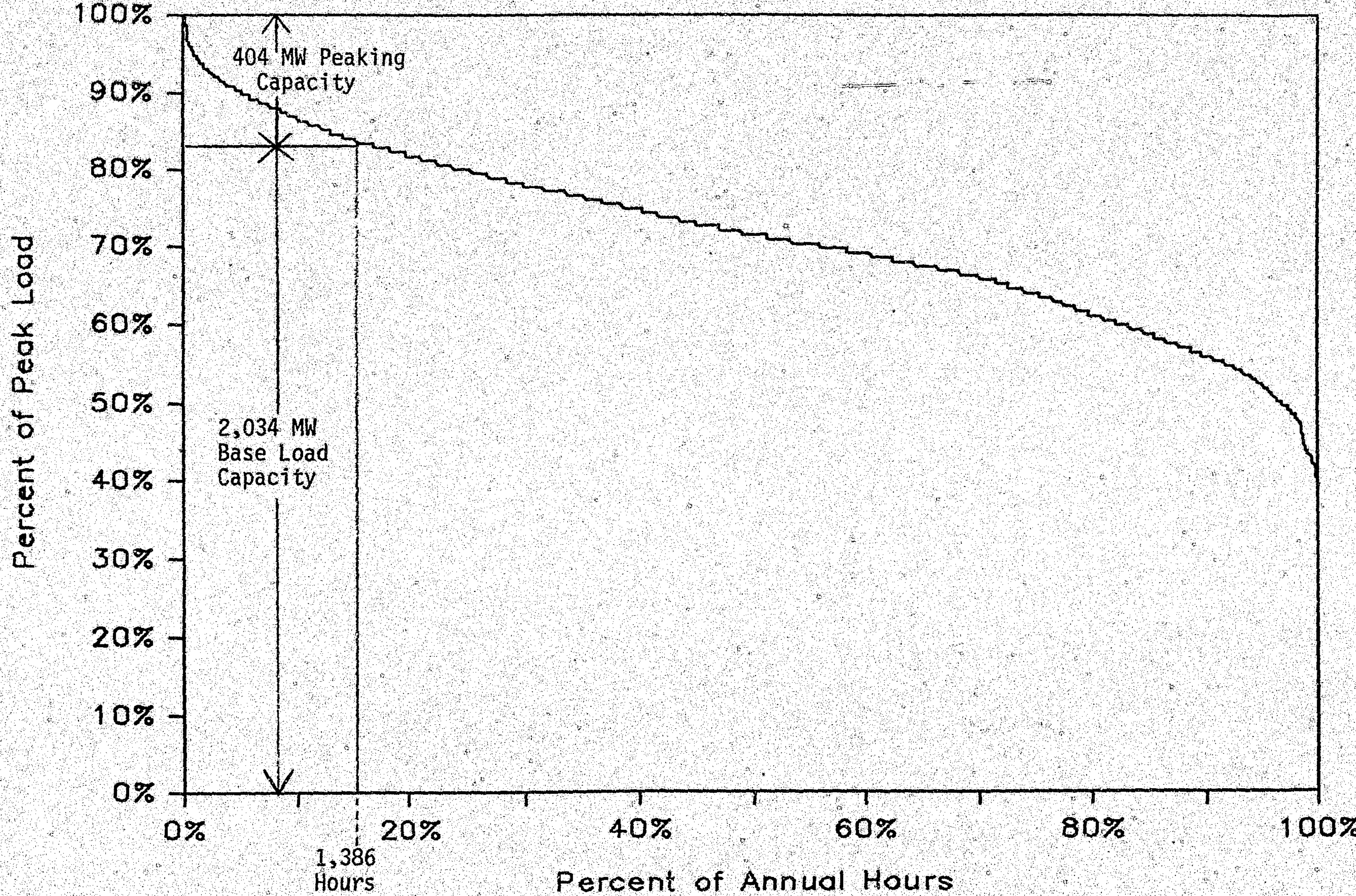


Exhibit JP-2 (     )
Schedule 4

PHILADELPHIA ELECTRIC COMPANY

Lowest Cost System Analysis
Capacity Requirements

| Line | Description | Total Company (1) | High Load Factor (2) |
|---|---|---|---|
| | Capacity (MW): | | |
| 1 | Base | 4,128 | 2,034 |
| 2 | Peaking | 1,797 | 404 |
| 3 | Total | 5,925 | 2,438 |
| | Percent Capacity Mix: | | |
| 4 | Base | 70% | 83% |
| 5 | Peaking | 30% | 17% |

PHILADELPHIA ELECTRIC COMPANY

Lowest Cost System Analysis
Energy Requirements and Generation Mix

| Line | Description | Total Company (1) | High Load Factor (2) |
|---|---|---|---|
| | Energy Requirements (MWh): | | |
| 1 | Base | 29,631,716 | 15,135,981 |
| 2 | Peaking | 531,192 | 168,749 |
| 3 | Total | 30,162,908 | 15,304,729 |
| | Generation Mix: | | |
| 4 | Base | 98.2% | 98.9% |
| 5 | Peaking | 1.8% | 1.1% |

# PHILADELPHIA ELECTRIC COMPANY

## Lowest Cost System Analysis
## Fixed and Variable Costs

| Line | Description | Base (1) | Peaking (2) | Total (3) | Units (4) | Per Unit Cost (5) |
|---|---|---|---|---|---|---|
| 1 | Fixed Costs | $243.38/kW* | $47.60/kW* | - | - | - |
| 2 | High Load Factor | $495,065 | $19,232 | $ 514,298 | 2,438 MW | $211/kW |
| 3 | Total System | $1,004,673 | $85,537 | $1,090,210 | 5,925 MW | $184/kW |
| 4 | Variable Costs | $.01669/kWh* | $.15799/kWh* | - | - | - |
| 5 | High Load Factor | $252,620 | $26,661 | $ 279,280 | 15,304.7 GWh | $.01825/kWh |
| 6 | Total System | $494,553 | $83,923 | $ 578,476 | 30,162.9 GWh | $.01918/kWh |
| | Total Cost | | | | | |
| 7 | High Load Factor | | | $ 793,578 | | |
| 8 | Total System | | | $1,668,686 | | |

*Schedule 2.

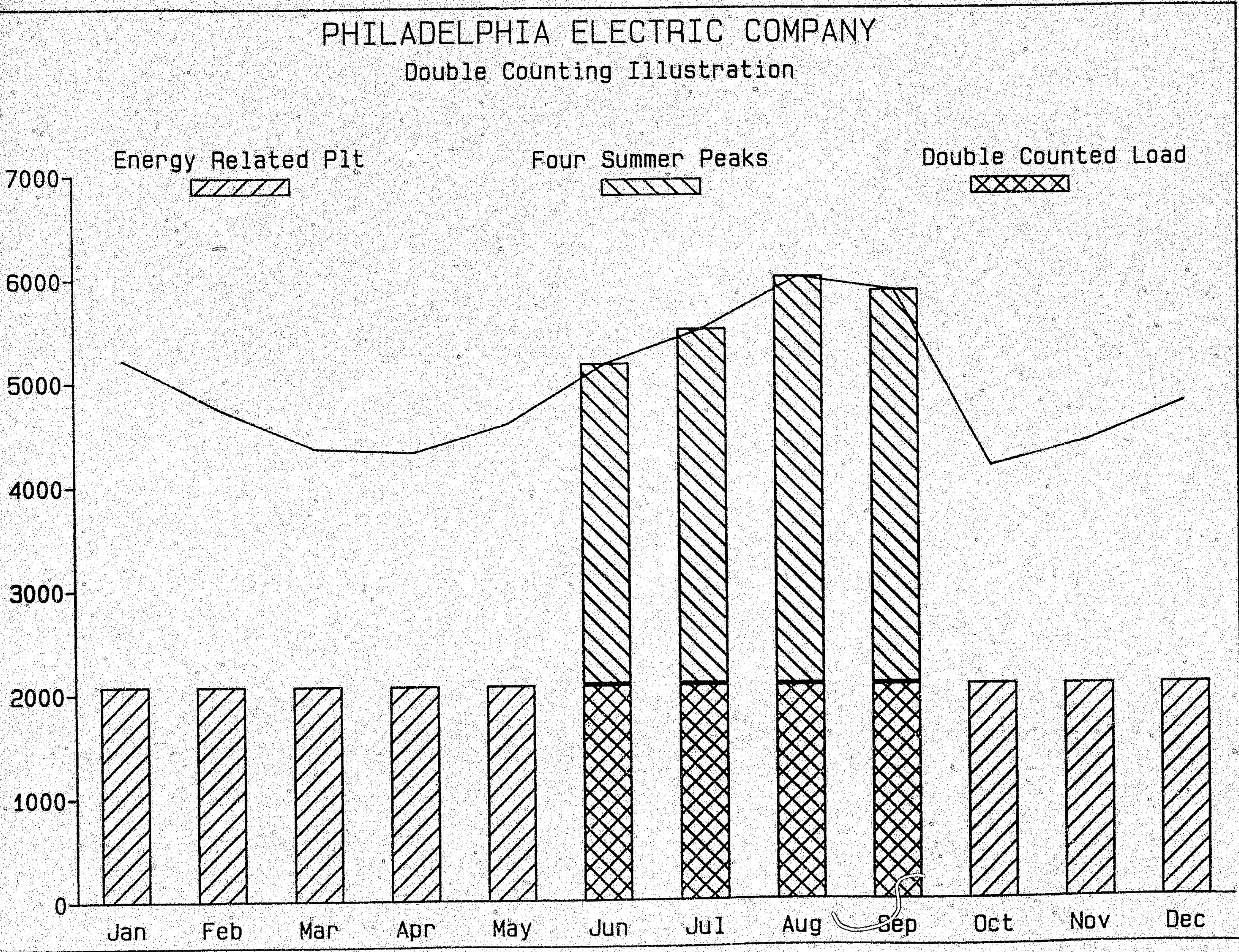


Exhibit JP-2 (     )
Schedule 8

PHILADELPHIA ELECTRIC COMPANY

Derivation of Peak and Average Demand
Allocation Factor Corrected for the Double-Counting Problem
Year Ending June 30, 1986

| Line | Customer Class | Four Peak Demand (kW) (1) | Average Demand Amount (kW) (2) | Average Demand Percent (3) | Demand Supplied by Energy-Related Plant* (kW) (4) | Excess Demand Amount (kW) (5) | Excess Demand Percent (6) | Corrected Peak and Average Percent** (7) |
|---|---|---|---|---|---|---|---|---|
| 1 | High Tension | 2,143,078 | 1,520,580 | 44.00271% | 916,355 | 1,226,723 | 33.20952% | 39.71388% |
| 2 | Primary | 469,779 | 280,706 | 8.12310 | 169,163 | 300,616 | 8.13819 | 8.12910 |
| 3 | Secondary | 816,090 | 432,405 | 12.51298 | 260,582 | 555,508 | 15.03856 | 13.51655 |
| 4 | Residential | 2,083,422 | 1,057,945 | 30.61493 | 637,555 | 1,475,394 | 39.94149 | 34.32097 |
| 5 | Street Lighting | 297 | 21,443 | 0.62053 | 12,923 | 0 | 0.00000 | 0.37395 |
| 6 | Other Utilities | 103,977 | 52,833 | 1.52889 | 31,839 | 72,138 | 1.95290 | 1.69737 |
| 7 | Interdepartmental | 11,248 | 7,529 | 0.21787 | 4,537 | 6,711 | 0.18167 | 0.20349 |
| 8 | SEPTA | 45,498 | 31,533 | 0.91251 | 19,003 | 26,495 | 0.71726 | 0.83493 |
| 9 | AMTRAK | 60,844 | 50,676 | 1.46648 | 30,539 | 30,305 | 0.82040 | 1.20975 |
| 10 | Total Company | 5,734,233 | 3,455,651 | 100.00000% | 2,082,497 | 3,693,888 | 100.00000% | 100.00000% |

*Average demand times 60%
**Column (3) times 60%, Column (6) times 40%

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PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
CORRECTED PEAK AND AVERAGE WITH A FUEL SYMMETRY ADJUSTMENT
1985 EDH STUDY
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

| | TOTAL | HIGH TENSION | PRIMARY | SECONDARY | RATE RH | RATE R | RATE OP |
|---|---|---|---|---|---|---|---|
| RATE BASE | | | | | | | |
| ELECTRIC PLANT IN SERVICE | $8,893,834 | $3,041,725 | $ 667,578 | $1,174,207 | $ 500,189 | $2,973,225 | $ 84,707 |
| ACCUMULATED PROVISION FOR DEPREC | 1,665,850 | 502,063 | 118,270 | 212,147 | 100,908 | 618,551 | 17,930 |
| NET PLANT IN SERVICE | 7,227,984 | 2,539,662 | 549,308 | 962,061 | 399,281 | 2,354,674 | 66,776 |
| RATE BASE ADJUSTMENTS | | | | | | | |
| ADDITIONS | | | | | | | |
| WORKING CAPITAL | 272,153 | 101,732 | 20,233 | 34,280 | 15,672 | 83,691 | 3,871 |
| DEDUCTIONS | | | | | | | |
| ACCELERATED AMORTIZATION | 2,323 | 923 | 189 | 314 | 120 | 657 | 20 |
| LIBERALIZED DEPRECIATION | 526,166 | 180,720 | 39,652 | 69,531 | 29,560 | 174,806 | 5,030 |
| RECOVERABLE FUEL COST | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL RATE BASE | 6,963,532 | 2,459,046 | 529,317 | 925,538 | 384,643 | 2,258,279 | 65,480 |
| REVENUE | | | | | | | |
| SALES | 2,251,817 | 785,557 | 178,729 | 328,244 | 121,780 | 699,286 | 23,392 |
| OTHER | 38,962 | 10,407 | 2,314 | 4,334 | 2,087 | 15,345 | 1,077 |
| TOTAL REVENUE | 2,290,779 | 795,964 | 181,043 | 332,578 | 123,867 | 714,631 | 24,469 |
| EXPENSES | | | | | | | |
| OPERATION AND MAINT EXP | 1,440,907 | 516,520 | 105,852 | 184,995 | 81,662 | 470,302 | 19,006 |
| DEPRECIATION AND AMORT | 264,877 | 93,722 | 20,306 | 34,609 | 14,578 | 85,084 | 2,820 |
| TAXES OTH THN INCOME TAX | 82,178 | 27,652 | 6,221 | 11,417 | 4,594 | 27,880 | 941 |
| INCOME TAXES | 34,032 | 16,955 | 8,124 | 19,896 | 151 | -16,239 | -451 |
| PROV FOR DEFERRED INC TAX | 41,011 | -963 | 2,474 | 6,937 | 1,806 | 26,438 | -399 |
| INC TX DEF IN PRIOR YR | -13,606 | -5,351 | -1,100 | -1,836 | -708 | -3,897 | -117 |
| INVESTMENT TAX CREDIT | -3,401 | -1,168 | -256 | -449 | -191 | -1,130 | -33 |
| GAIN FROM DISPOSITION OF UTL PROP | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL EXPENSES | 1,845,998 | 647,367 | 141,621 | 255,569 | 101,891 | 588,437 | 21,769 |
| NET OPERATING INCOME | 444,781 | 148,597 | 39,422 | 77,008 | 21,976 | 126,194 | 2,700 |
| RATE OF RETURN | 6.39% | 6.04% | 7.45% | 8.32% | 5.71% | 5.59% | 4.12% |
| INDEX OF RETURN | 100 | 95 | 117 | 130 | 89 | 87 | 65 |
| DEVIATION | .00 | -.34 | 1.06 | 1.93 | -.67 | -.80 | -2.26 |
| REVENUE SUBSIDY | 0 | -17,204 | 11,402 | 36,344 | -5,267 | -36,664 | -3,012 |
| PROPOSED OPERATING INCOME | $ 884,369 | $ 324,465 | $ 76,406 | $ 140,887 | $ 45,010 | $ 259,135 | $ 4,160 |
| PROPOSED RATE OF RETURN | 12.70% | 13.19% | 14.43% | 15.22% | 11.70% | 11.47% | 6.35% |
| PROPOSED INDEX OF RETURN | 100 | 104 | 114 | 120 | 92 | 90 | 50 |
| PROPOSED DEVIATION | .00 | .49 | 1.73 | 2.52 | -1.00 | -1.23 | -6.35 |
| PROPOSED REVENUE SUBSIDY | 0 | 24,713 | 18,653 | 47,419 | -7,801 | -56,202 | -8,442 |

Exhibit JP-2 (      )
Schedule 10
Page 1 of 2

02/12/86 15:49

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
CORRECTED PEAK AND AVERAGE WITH A FUEL SYMMETRY ADJUSTMENT
1985 EDH STUDY
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

| | RATE SLP | RATE SLS | OTH SL | OTHER UTILITIES | INTER DEPARTMT | SEPTA | AMTRAK |
|---|---|---|---|---|---|---|---|
| RATE BASE | | | | | | | |
| ELECTRIC PLANT IN SERVICE | $ 62,651 | $ 75,959 | $ 7,877 | $ 127,306 | $ 15,750 | $ 68,459 | $ 94,200 |
| ACCUMULATED PROVISION FOR DEPREC | 17,869 | 24,543 | 2,245 | 20,571 | 2,638 | 11,968 | 16,147 |
| NET PLANT IN SERVICE | 44,782 | 51,416 | 5,632 | 106,735 | 13,113 | 56,491 | 78,053 |
| RATE BASE ADJUSTMENTS | | | | | | | |
| ADDITIONS | | | | | | | |
| WORKING CAPITAL | 1,364 | 1,299 | 211 | 3,568 | 479 | 2,134 | 3,619 |
| DEDUCTIONS | | | | | | | |
| ACCELERATED AMORTIZATION | 5 | 3 | 1 | 39 | 5 | 19 | 28 |
| LIBERALIZED DEPRECIATION | 3,726 | 4,515 | 468 | 7,568 | 935 | 4,067 | 5,589 |
| RECOVERABLE FUEL COST | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL RATE BASE | 42,163 | 47,845 | 5,347 | 102,696 | 12,652 | 54,500 | 76,026 |
| REVENUE | | | | | | | |
| SALES | 13,431 | 17,722 | 2,300 | 29,633 | 4,803 | 18,244 | 28,696 |
| OTHER | 63 | 40 | 33 | 283 | 35 | 213 | 2,733 |
| TOTAL REVENUE | 13,494 | 17,762 | 2,333 | 29,916 | 4,838 | 18,457 | 31,429 |
| EXPENSES | | | | | | | |
| OPERATION AND MAINT EXP | 7,117 | 7,163 | 1,101 | 15,290 | 1,918 | 10,904 | 19,077 |
| DEPRECIATION AND AMORT | 1,545 | 2,601 | 249 | 3,945 | 483 | 2,053 | 2,881 |
| TAXES OTH THN INCOME TAX | 540 | 672 | 84 | 497 | 62 | 626 | 992 |
| INCOME TAXES | 612 | 1,311 | 245 | -482 | 489 | 959 | 2,461 |
| PROV FOR DEFERRED INC TAX | 539 | 894 | 52 | 3,016 | 367 | 69 | -220 |
| INC TX DEF IN PRIOR YR | -33 | -25 | -5 | -228 | -27 | -113 | -163 |
| INVESTMENT TAX CREDIT | -24 | -29 | -3 | -49 | -6 | -26 | -36 |
| GAIN FROM DISPOSITION OF UTL PROP | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL EXPENSES | 10,297 | 12,586 | 1,722 | 21,988 | 3,285 | 14,473 | 24,993 |
| NET OPERATING INCOME | 3,198 | 5,175 | 611 | 7,928 | 1,553 | 3,984 | 6,436 |
| RATE OF RETURN | 7.58% | 10.82% | 11.42% | 7.72% | 12.27% | 7.31% | 8.47% |
| INDEX OF RETURN | 119 | 169 | 179 | 121 | 192 | 114 | 133 |
| DEVIATION | 1.20 | 4.43 | 5.04 | 1.33 | 5.88 | .92 | 2.08 |
| REVENUE SUBSIDY | 1,025 | 4,305 | 547 | 2,779 | 1,512 | 1,022 | 3,210 |
| PROPOSED OPERATING INCOME | $ 3,560 | $ 5,400 | $ 664 | $ 7,929 | $ 1,553 | $ 6,447 | $ 8,754 |
| PROPOSED RATE OF RETURN | 8.44% | 11.29% | 12.42% | 7.72% | 12.27% | 11.83% | 11.52% |
| PROPOSED INDEX OF RETURN | 66 | 89 | 98 | 61 | 97 | 93 | 91 |
| PROPOSED DEVIATION | -4.26 | -1.41 | -.28 | -4.98 | -.43 | -.87 | -1.18 |
| PROPOSED REVENUE SUBSIDY | -3,646 | -1,373 | -31 | -10,387 | -110 | -964 | -1,830 |

Exhibit JP-2 ( )
Schedule 10
Page 2 of 2

PHILADELPHIA ELECTRIC COMPANY

Adjusted Fuel Cost Allocation Factors by Customer Class
to Correct the Fuel Symmetry Problem
Year Ending June 30, 1986

| Line | Customer Class | Fuel and Purchased Power Cost: Of Non-Base Units[(a)] (1) | Fuel and Purchased Power Cost: Of Base Units[(b)] (2) | Fuel and Purchased Power Cost: Total (3) | Fuel Cost Allocation Factor (4) |
|---|---|---|---|---|---|
| 1 | High Tension | $118,266,952 | $123,915,633 | $242,182,586 | 40.58628% |
| 2 | Primary | 30,251,152 | 19,264,378 | 49,515,529 | 8.29808 |
| 3 | Secondary | 54,435,442 | 26,314,089 | 80,749,530 | 13.53245 |
| | Residential: | | | | |
| 4 | Heating | 14,863,509 | 16,622,125 | 31,485,635 | 5.27653 |
| 5 | Regular | 119,598,825 | 41,583,896 | 161,182,721 | 27.01188 |
| 6 | Rate OP | 0 | 5,627,430 | 5,627,430 | 0.94308 |
| 7 | Total Residential | 134,462,334 | 63,833,451 | 198,295,786 | 33.23149 |
| | Street Lighting: | | | | |
| 8 | Rate SLP | 0 | 1,371,087 | 1,371,087 | 0.22977 |
| 9 | Rate SLS | 0 | 866,110 | 866,110 | 0.14515 |
| 10 | All Other | 0 | 225,656 | 225,656 | 0.03782 |
| 11 | Total Street Ltg. | 0 | 2,462,854 | 2,462,854 | 0.41274 |
| 12 | Other Utilities | 6,958,521 | 3,083,319 | 10,041,840 | 1.68287 |
| 13 | Interdepartmental | 666,576 | 578,803 | 1,245,379 | 0.20871 |
| 14 | SEPTA | 2,591,567 | 2,510,111 | 5,101,677 | 0.85497 |
| 15 | AMTRAK | 2,267,555 | 4,847,754 | 7,115,309 | 1.19242 |
| 16 | Total Company | $349,900,098 | $246,810,392 | $596,710,490 | 100.00000% |

(a) Allocated on Page 2, Column 6

(b) Allocated on Page 2, Column 4

PHILADELPHIA ELECTRIC COMPANY

Derivation of Class Energy Requirements Met from Base and Nonbase Units
Year Ending June 30, 1986

| Line | Customer Class | Energy Required (MWh) (1) | Load Factor (2) | Base Energy Requirement Amount (MWh) (3) | Base Energy Requirement Percent (4) | Nonbase Energy Requirement Amount (MWh) (5) | Nonbase Energy Requirement Percent (6) |
|---|---|---|---|---|---|---|---|
| 1 | High Tension | 13,320,283 | 71.0% | 9,451,154 | 50.21% | 3,869,129 | 33.80% |
| 2 | Primary | 2,458,984 | 59.8 | 1,469,311 | 7.81 | 989,673 | 8.65 |
| 3 | Secondary | 3,787,866 | 53.0 | 2,006,999 | 10.66 | 1,780,867 | 15.56 |
| | Residential: | | | | | | |
| 4 | Heating | 1,754,047 | 72.3 | 1,267,784 | 6.73 | 486,263 | 4.25 |
| 5 | Regular | 7,084,342 | 44.8 | 3,171,640 | 16.85 | 3,912,702 | 34.18 |
| 6 | Rate OP | 429,209 | N/M | 429,209 | 2.28 | 0 | 0.00 |
| 7 | Total Residential | 9,267,598 | 50.8 | 4,868,633 | 25.86 | 4,398,965 | 38.43 |
| | Street Lighting: | | | | | | |
| 8 | Rate SLP | 104,574 | N/M | 104,574 | 0.56 | 0 | 0.00 |
| 9 | Rate SLS | 66,059 | N/M | 66,059 | 0.35 | 0 | 0.00 |
| 10 | All Other | 17,211 | N/M | 17,211 | 0.09 | 0 | 0.00 |
| 11 | Total Street Ltg. | 187,844 | N/M | 187,844 | 1.00 | 0 | 0.00 |
| 12 | Other Utilities | 462,817 | 50.8 | 235,167 | 1.25 | 227,650 | 1.99 |
| 13 | Interdepartmental | 65,953 | 66.9 | 44,146 | 0.23 | 21,807 | 0.19 |
| 14 | SEPTA | 276,232 | 69.3 | 191,448 | 1.02 | 84,784 | 0.74 |
| 15 | AMTRAK | 443,926 | 83.3 | 369,742 | 1.96 | 74,184 | 0.65 |
| 16 | Total Company | 30,271,503 | 60.3% | 18,824,444 | 100.00% | 11,447,059 | 100.00% |

PHILADELPHIA ELECTRIC COMPANY

Fuel Expense and Energy Supplied from Base Load Units
July 1986 - June 1988

| Line | Description | Fuel Expense (1) | Energy (MWh) (2) | Average Cost per kWh (Mills) (3) |
|---|---|---|---|---|
| | Base Load Resources: | | | |
| 1 | Coal - PE Steam | $127,142,000 | 5,698,000 | 22.31 |
| 2 | Coal - Minemouth | 111,573,000 | 7,779,000 | 14.34 |
| 3 | Nuclear | 215,962,998 | 31,206,601 | 6.92 |
| 4 | Total Base Load | 454,677,998 | 44,683,601 | 10.18 |
| 5 | Nonbase Load Resources | 506,728,850 | 15,899,874 | 31.87 |
| 6 | Total | $961,406,848 | 60,583,475 | 15.87 |

# PHILADELPHIA ELECTRIC COMPANY

## Comparison Between PECO, PBUUG and UP/UUC Proposed HT Rate Designs

| Line | Description | Present Rates (1) | Proposed Rates (2) | Percent Increase (3) |
|---|---|---|---|---|
| | PECO | | | |
| 1 | Customer Charge | $220.45 | $264.15 | 19.8 % |
| 2 | Capacity Charge | 5.37 | 9.44 | 75.8 |
| | Energy Charges: | | | |
| 3 | First 150 Hours | .0739 | .0964 | 30.4 |
| 4 | Next 150 Hours | .0556 | .0668 | 20.1 |
| 5 | Additional | .0376 | .0375 | ( 0.3) |
| | PBUUG (Exhibit RLF 7) | | | |
| 6 | Customer Charge | | $230.20 | 4.4 % |
| 7 | Capacity Charge | | 6.18 | 15.1 |
| | Energy Charges: | | | |
| 8 | First 150 Hours | | .0928 | 25.6 |
| 9 | Next 150 Hours | | .0733 | 31.8 |
| 10 | Additional | | .0541 | 43.9 |
| | UP/UUC (Exhibit RMW-19) | | | |
| 11 | Customer Charge | | $264.15 | 19.8 % |
| 12 | Capacity Charge | | 5.77 | 7.4 |
| | Energy Charges: | | | |
| 13 | First 150 Hours | | .0940 | 27.2 |
| 14 | Next 150 Hours | | .0764 | 37.4 |
| 15 | Additional | | .0591 | 57.2 |

PHILADELPHIA ELECTRIC COMPANY

Impact of UP/UUC Recommended HT Design
on PAIEUG et al Electricity Cost

| Line | Description | PAIEUG et al (1) | Total High Tension Class (2) |
|---|---|---|---|
| | Base Rate Percent Increase | | |
| 1 | PECO Proposed | 24.1% | 29.6% |
| 2 | UP/UUC Recommended | 37.4% | 31.0% |
| 3 | Percent Difference | 55% | 5% |
| | Nonfuel Percent Increase | | |
| 4 | PECO Proposed | 71.9% | 70.6% |
| 5 | UP/UUC Recommended | 98.0% | 73.0% |
| 6 | Percent Difference | 36% | 3% |

# PHILADELPHIA ELECTRIC COMPANY

## Comparison Between PECO, PBUUG and UP/UUC Proposed HT Rate Designs Equivalent Capacity and Energy Rates*

| Line | Description | Present Rates (1) | PECO Proposed (2) | PBUUG Recommended (3) | UP/UUC Recommended (4) |
|---|---|---|---|---|---|
| | Up to 149 Hours' Use | | | | |
| 1 | Capacity Charge | $ 5.37 | $ 9.44 | $ 6.18 | $ 5.77 |
| 2 | Percent Increase | | 76% | 15% | 7% |
| 3 | Nonfuel Energy Charge | .04515 | .07515 | .07155 | .07275 |
| 4 | Percent Increase | | 66% | 58% | 61% |
| | 150-299 Hours' Use | | | | |
| 5 | Capacity Charge | $ 8.115 | $ 13.88 | $ 9.105 | $ 8.41 |
| 6 | Percent Increase | | 71% | 12% | 4% |
| 7 | Nonfuel Energy Charge | .02685 | .04555 | .05205 | .05515 |
| 8 | Percent Increase | | 70% | 94% | 105% |
| | 300 Hours' Use and Above | | | | |
| 9 | Capacity Charge | $13.515 | $22.670 | $14.865 | $ 13.60 |
| 10 | Percent Increase | | 68% | 10% | 1% |
| 11 | Nonfuel Energy Charge | .00885 | .01625 | .03285 | .03785 |
| 12 | Percent Increase | | 84% | 271% | 328% |

*Below 50 MW of demand.

PHILADELPHIA ELECTRIC COMPANY

Rate HT Income Versus Consumption
Summary

| | | Income Fluctuation Due to a 2% Fluctuation in Consumption | | | | | |
|---|---|---|---|---|---|---|---|
| | | Equal Fluctuations in Demand and Energy | | Demand Fluctuation =50% of Energy Fluctuation | | No Demand Fluctuation | |
| Line | Proposal | Percent (1) | Index (2) | Percent (3) | Index (4) | Percent (5) | Index (6) |
| 1 | PECO | 2.39% | 103 | 1.99% | 105 | 1.59% | 110 |
| 2 | PAIEUG et al | 2.33% | 100 | 1.90% | 100 | 1.45% | 100 |
| 3 | UP/UUC | 2.47% | 106 | 2.22% | 117 | 1.98% | 137 |

PHILADELPHIA ELECTRIC COMPANY

Rate HT Income Versus Consumption
at PECO Proposed Rates

| Line | Description | Amount (1) | Reference (2) |
|---|---|---|---|
| 1 | Energy Sold (MWh) | 12,947,425 | DR-Staff-RSC-1 |
| 2 | 2% Variation (MWh) | 258,949 | Line 1 x .02 |
| 3 | Margin in Energy Rate (6.620¢ - 2.604¢) | 4.016¢ | WFS-1, Page 39 |
| 4 | Billing Demand (kW) | 27,933,000 | Estimated |
| 5 | 1% Variation | 279,330 | Line 4 x .01 |
| 6 | Rate | $9.44 | JP-2, Schedule 12 |
| | Revenue Effect: | | |
| 7 | Energy | $ 10,399,392 | Line 2 x Line 3 |
| 8 | Demand | 2,636,875 | Line 5 x Line 6 |
| 9 | Total | 13,036,267 | |
| 10 | Income Effect | 6,417,381 | Line 9 ÷ 2.0314 |
| 11 | Net Operating Income | $322,508,000 | MPB-3, Schedule 2 |
| 12 | Variation in Income | 1.99% | Line 10 ÷ Line 11 |

# PHILADELPHIA ELECTRIC COMPANY

## Rate HT Income Versus Consumption at PAIEUG et al Proposed Rates

| Line | Description | Amount (1) | Reference (2) |
|---|---|---|---|
| 1 | Energy Sold (MWh) | 12,947,425 | DR-Staff-RSC-1 |
| 2 | 2% Variation (MWh) | 258,949 | Line 1 x .02 |
| 3 | Margin in Energy Rate (6.309¢ - 2.604¢) | 3.705¢ | WFS-1, Page 39 |
| 4 | Billing Demand (kW) | 27,933,000 | Estimated |
| 5 | 1% Variation | 279,330 | Line 4 x .01 |
| 6 | Rate | $10.19 | JP-1, Schedule 8 |
| | Revenue Effect: | | |
| 7 | Energy | $ 9,594,060 | Line 2 x Line 3 |
| 8 | Demand | 2,846,373 | Line 5 x Line 6 |
| 9 | Total | 12,440,433 | |
| 10 | Income Effect | 6,124,068 | Line 9 ÷ 2.0314 |
| 11 | Net Operating Income | $322,508,000 | MPB-3, Schedule 2 |
| 12 | Variation in Income | 1.90% | Line 10 ÷ Line 11 |

# PHILADELPHIA ELECTRIC COMPANY

## Rate HT Income Versus Consumption at UP/UUC Proposed Rates

| Line | Description | Amount (1) | Reference (2) |
|---|---|---|---|
| 1 | Energy Sold (MWh) | 12,947,425 | DR-Staff-RSC-1 |
| 2 | 2% Variation (MWh) | 258,949 | Line 1 x .02 |
| 3 | Margin in Energy Rate (7.608¢ - 2.604¢) | 5.004¢ | WFS-1, Page 39 |
| 4 | Billing Demand (kW) | 27,933,000 | Estimated |
| 5 | 1% Variation | 279,330 | Line 4 x .01 |
| 6 | Rate | $5.77 | JP-2, Schedule 12 |
| | Revenue Effect: | | |
| 7 | Energy | $ 12,957,808 | Line 2 x Line 3 |
| 8 | Demand | 1,611,734 | Line 5 x Line 6 |
| 9 | Total | 14,569,542 | |
| 10 | Income Effect | 7,172,168 | Line 9 ÷ 2.0314 |
| 11 | Net Operating Income | $322,508,000 | MPB-3, Schedule 2 |
| 12 | Variation in Income | 2.22% | Line 10 ÷ Line 11 |

PHILADELPHIA ELECTRIC COMPANY

Hypothetical Example Demonstrating the Intraclass Revenue Allocation With and Without a Demand Ratchet

| Line | Description | Total Class (1) | Customer "A" (2) | Customer "B" (3) |
|---|---|---|---|---|
| 1 | Demand Cost | $1,000,000 | $500,000 | $500,000 |
| 2 | Coincident Demand (MW) | 1,000 | 500 | 500 |
| | Monthly Maximum Demand (MW) | | | |
| 3 | January | 825 | 525 | 300 |
| 4 | February | 825 | 525 | 300 |
| 5 | March | 825 | 525 | 300 |
| 6 | April | 825 | 525 | 300 |
| 7 | May | 825 | 525 | 300 |
| 8 | June | 1,200 | 575 | 625 |
| 9 | July | 1,200 | 575 | 625 |
| 10 | August | 1,200 | 575 | 625 |
| 11 | September | 1,200 | 575 | 625 |
| 12 | October | 825 | 525 | 300 |
| 13 | November | 825 | 525 | 300 |
| 14 | December | 825 | 525 | 300 |
| 15 | Total | 11,400 | 6,500 | 4,900 |
| 16 | Demand Cost if Allocated on Sum of Monthly Maximum Demands | $1,000,000 | $570,175 | $429,825 |
| 17 | Billing Demand With 80% Ratchet (MW) | 13,000 | 6,500 | 6,500* |
| 18 | Demand Cost if Allocated on Billing Demand | $1,000,000 | $500,000 | $500,000 |

*80% of 625 MW x 8 months + 625 MW x 4 months.

PHILADELPHIA ELECTRIC COMPANY

## Survey of Utility Tariff Provisions

| Line | U t i l i t y | Rate Schedule (1) | Demand Ratchet/ Minimum Charge (2) | Demand Interval (Minutes) (3) | Seasonal Differential (4) |
|---|---|---|---|---|---|
| 1 | Atlantic City Electric Company | AGS | 80% of Highest Demand (June - October) | 15 | Yes |
| 2 | Baltimore Gas and Electric Company | P | Customer Charge + Demand Charge x 1,500 kW | 30 | Yes* |
| 3 | Consolidated Edison Company of New York, Inc. | SC-4 | - | 30 | Yes* |
| 4 | Delmarva Power & Light Company | GP | 25% On-Peak + 75% of Average Billing Demands for Prior June - September | 60 | Yes* |
| 5 | Duquesne Light Company | L | Greater of 70% of Contract On-Peak Demand or 5,000 kW | 15 | No |
| 6 | Jersey Central Power & Light Company | GP | Monthly Charges plus $3.50/kW of Highest of: (1) On or Off-Peak (Prior 12 Months) or (2) Contract Demand | 15 | Yes* |
| 7 | Metropolitan Edison Company | GP | 50% of Highest Demand (Prior 11 Months) | 15 | No* |
| 8 | Pennsylvania Electric Company | GP | Customer Charge + 50% of Highest Demand (Prior 11 Months) | 15 | No* |
| 9 | Pennsylvania Power Company | GP | 60% of Highest Demand (Prior 11 Months) or Contract | 15 | No |
| 10 | Pennsylvania Power & Light Company | LP-4 | - | 15 | No |
| 11 | Potomac Electric Power Company | GT | Customer Charge + Distribution Charge | 30 | Yes* |
| 12 | Public Service Electric and Gas Company | LPL | Demand Charge + $1.75/kW On-Peak Demand (Current Month or Prior June - September) | 15 | Yes* |

*Time-of-use differentials.

SEPTA/Amtrak Statement No. 1A

p4 3-10-86
Nb7

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152

REBUTTAL TESTIMONY OF
RICHARD J. RUDDEN

on behalf of

THE SOUTHEASTERN PENNSYLVANIA TRANSPORTATION AUTHORITY

and

THE NATIONAL RAILROAD PASSENGER CORPORATION



Concerning Rate Structure

February 26, 1986

Rebuttal Testimony of Richard J. Rudden
on Behalf of SEPTA and Amtrak

Q. Mr. Rudden, what is the purpose of your rebuttal testimony?

A. My purpose is to respond to testimony that has been submitted b various intervenors proposing alternative revenue allocations for SEPTA and Amtrak.

Q. Would you please summarize the conclusions of your rebuttal testimony?

A. Yes. PECO's proposed separate rate classification and cost based rates for SEPTA and Amtrak represent an appropriate response to the Commission's order in the last case (Docket No. R-842590) in which PECO was directed to submit: (1) cost studies indicating the cost of providing service to SEPTA and Amtrak; and (2) alternative rate designs reflecting the results of such studies. In complying with the Commission's order, PECO has used the 4CP cost allocation methodology approved in that case.

By contrast, various intervenor groups have submitted alternative cost allocation methodologies and/or class revenue apportionments which differ from those proposed by PECO. These alternative proposals are inappropriate in that they (1) fail to give proper effect to the Commission's order in Docket No. R-842590; (2) propose inappropriate departures from the 4CP cost allocation methodology that has been repeatedly accepted by the Commission; and/or (3) fail to take into account the unique supply and cost characteristics of SEPTA and Amtrak.

Q. Could you please explain the circumstances surrounding the Commission's order in Docket No. R-842590?

A. In the last case, both SEPTA and Amtrak argued that the available evidence indicated that the costs of providing electric traction power are lower than the costs of providing service to HT customers in general, and that the railroads should be separated from the HT class for costing and ratemaking purposes. Although it did not adopt or implement the recommendations of SEPTA and Amtrak regarding a separate rate classification or rider at that time, the Commission was sufficiently concerned about the issue to direct PECO to submit studies indicating the cost of providing service to SEPTA and Amtrak as well as alternative rate designs reflecting the results of those studies.

Q. Did the Company perform such a study in compliance with the Commission's order?

A. Yes. The study submitted in this case is the basis upon which PECO proposes separate ratemaking treatment for SEPTA and Amtrak relative to the HT class. The PECO study results confirm that the costs of serving SEPTA and Amtrak are significantly less than serving HT customers in general. The cost allocation process used by PECO in its special study, utilizing the 4CP method, is the same as that adopted by this Commission in the last seven rate cases. This method has been approved by the Commission in past cases even where a substantial portion of the relevant rate base (i.e. approximately 50%) consisted of nuclear generating plant. In addition, PECO's cost allocation has been improved in this case by inclusion of a detailed analysis of specific distribution facilities serving SEPTA and Amtrak.

Q. Under PECO's proposal, do SEPTA and Amtrak pay their full cost of service?

A. Yes. They pay for all costs allocated to them, including the full system average rate of return. In my opinion, this result is entirely consistent with the Commission's order in the last case.

Q. In your summary of conclusions, you state that several of the intervenors fail to give proper effect to the Commission's order in Docket No. R-842590. Please explain.

A. First, the Philadelphia Area Industrial Energy Users Group ("P.A.I.E.U.G.") has offered a proposal which perpetuates the past inequities or subsidies which the Commission in Docket No. R-842590 apparently sought to investigate and, if appropriate, remedy. Specifically, the P.A.I.E.U.G. has proposed that SEPTA and Amtrak continue to pay the same interclass subsidy which they pay under the present HT rate, i.e. more than $5 million. While proposing the system average rate of return for itself, the P.A.I.E.U.G. proposes that SEPTA and Amtrak pay rates substantially higher than the system average rate of return in their new rate classifications. Significantly, P.A.I.E.U.G.'s own cost of service study shows that, under PECO's proposed rates, SEPTA and Amtrak would pay very close to the system average rate of return (See Exhibit JP-1, Schedule 6).

Similarly, the Utility Users Committee/University of Pennsylvania ("UUC/UP") has effectively urged an abandonment of cost-based rates not only for SEPTA and Amtrak but for all classes through its recommendation that the revenue increase be allocated on a uniform percentage across all classes. Ironically, the UUC/UP has recommended that this equal percentage increase be applied to existing rates which were developed on the basis of PECO's 4CP methodology, as approved in the last case. Even though the UUC/UP thus implicitly adopts the 4CP methodology, this intervenor ignores the two current 4CP studies of record in this case (those of PECO and the P.A.I.E.U.G.). Both of the current 4CP studies demonstrate that under PECO's proposed rates, SEPTA and Amtrak would pay the system average rate of return, or very close to it.

As noted above, in the last rate case, PECo was ordered to perform studies to determine the actual costs of serving SEPTA and Amtrak. In my opinion, the uniform percentage increase proposed by the UUC/UP renders any such studies irrelevant and the proposal represents an unwarranted departure from cost based ratemaking.

Q. You have also stated above that certain intervenors have proposed inappropriate departures from the cost allocation methodologies accepted by this Commission in past cases. Please explain.

A. The Commission has reaffirmed its acceptance of the 4CP cost allocation methodology as it applies to PECO in a large number of past rate cases. Most significantly, it adopted the 4CP methodology in the last case, when approximately 50% of PECO's net production and transmission plant in service was accounted for by nuclear generation. Expressed as a percentage of total net generation plant only, the cost of nuclear generation facilities accounted for more than 60%.

In this case, some intervenors have argued that the allocation methodology should be changed to give weight to average demand in the determination of the A.1 allocator, citing the energy versus demand cost trade-offs inherent in the economics of nuclear power. I have three major problems with their proposals.

Q. What are they?

A. First, an essential ingredient of the "reasonableness" of any cost allocation methodology is its past acceptance by regulators.

In PECO's case, the Commission has clearly found the 4CP methodology acceptable, even where a significant portion of rate base was related to nuclear plant investments. The alternative cost allocation proposals put forth in this case do not appear to have any past acceptance by this Commission in PECO's rate cases.

Second, the applications of the alternative approaches are assymetrical, yielding inequitable results. While attempting to apportion the capital related costs of nuclear power as between demand and energy, the intervenors give no recognition to the differences in fuel costs associated with peak load versus base load energy. If they had recognized these fuel cost differences, off-peak and high load factor customers who use proportionately more base load power would have been allocated lower than average fuel costs. Proper recognition of these fuel cost differences could significantly reduce the cost responsibility of these customers relative to that shown by the proponents of the energy-weighted demand allocation methodologies. In this case, we have seen just one side of the coin; to accept the one-sided, energy-weighted demand allocation methodologies proposed in this case would be, in my opinion, discriminatory against off-peak and high load factor customers.

Third, the departure away from the 4CP methodology to an energy-weighted demand allocation method has been rationalized by some of the intervenors by arguing that a new allocation methodology is required to reduce the "rate shock" of Limerick. In my opinion, this is entirely inappropriate.

Q. Please explain why.

A. The proper mechanism for reducing rate shock is the phasing-in of Limerick's prudently incurred costs, not a change in cost allocation methodology. If a change in allocation methodology is to be adopted, it should be adopted for reasons related to basic utility design, operating and cost criteria, and not to achieve some predetermined objective, such as the mitigation of adverse rate impacts. If mitigation is to be an objective, it should be accomplished through rate design, as PECO has proposed. Moreover, a change in cost allocation methodology simply <u>shifts</u> relative impacts among classes, and does not reduce total costs for the system as a whole.

Q. You stated above that various intervenors have failed to take into account the unique service, supply and cost characteristics applicable to SEPTA and Amtrak. Please explain.

A. By and large, each intervenor rate structure witness who has proposed alternative cost and/or interclass revenue allocations in this proceeding has disregarded the unique load and supply characteristics of SEPTA and Amtrak which result in significantly lower costs of providing traction power. Most notably, none of the intervenor rate structure witnesses have taken into account (or even professed familiarity with) the special circumstances under which power is delivered to Amtrak at Thorndale and Perryville, as detailed in my direct testimony. Had they familiarized themselves with that testimony, they would have learned that nearly 38% of Amtrak's total energy requirements from PECO represent deliveries of power generated by other utilities and not by PECO. In fact, PECO neither generates the power which it meters at Thorndale and Perryville, nor transmits it to Amtrak. Moreover, the power metered at Thorndale and Perryville is 25Hz power, the vast majority of which is generated at Safe Harbor, a hydroelectric plant jointly owned by Pennsylvania Power & Light Company and Baltimore Gas and Electric Company, and delivered directly to Amtrak entirely outside of the PECO system.

Q. How does the failure to take into account the circumstances surrounding the delivery of power to Amtrak at Thorndale and Perryville affect the allocations of costs and revenue distributions proposed by the various intervenors?

A. In general, all of the cost allocation proposals submitted by the various intervenors overstate the amount of PECO production and transmission costs that should be allocated to Amtrak by a significant amount, corresponding to the amount of demand and/or energy metered at those delivery points.

Q. In your direct testimony, you discussed the impact upon Amtrak's revenue allocation resulting from the inclusion of power deliveries at Thorndale and Perryville in PECO's 4CP demand allocator. How do the circumstances surrounding the delivery of power at Thorndale and Perryville affect the cost allocation proposals submitted by those intervenors (i.e. the OCA, CEPA and PBUUG) who are recommending that a portion of PECO production and transmission costs be allocated on an energy basis?

A. These proposals are intended to allocate the costs of energy-related production capacity to customers who receive the benefit of this generating capacity in proportion to the energy generated and consumed from these facilities. Since the energy metered at Thorndale and Perryville is not generated (or transmitted) by any PECO facility, Amtrak cannot be expected to bear responsibility for PECO's energy-related production plant costs based on the amount of energy metered at Thorndale and Perryville. If an energy-weighted demand allocator were to be accepted by the Commission, the energy delivered at Thorndale and Perryville should be excluded from the computation of the demand allocation factor for SEPTA/Amtrak.

Q. Have you quantified the impact on the revenue allocation to Amtrak under the various parties' proposals if the Thorndale and Perryville demands and energies had been properly excluded from the allocation of PECO's production and transmission plant?

A. Yes, I have. In my direct testimony at pages 24-27, I addressed PECO's cost allocation study. To the extent that power deliveries at Thorndale and Perryville are included in the 4CP for allocation of production and transmission plant, an over-allocation of demand costs results. Such overstatement of demand costs results in an overstatement of revenue requirement of $5-6 million for Amtrak. For the cost study sponsored by the P.A.I.E.U.G. witnesses, I removed from the 4CP demands used in their A.1 allocator a level of demand which represents the lowest proportionate share of Amtrak's total 4CP demand historically provided at Thorndale and Perryville (i.e. 13,000 KW adjusted for losses). This results in a decrease in the P.A.I.E.U.G. revenue allocation for Amtrak of $4.6 million and a decrease, relative to PECO's proposal, of $4.2 million in the revenues required from Amtrak.

With regard to the peak and average method of cost allocation proposed by the OCA witness (and also apparently by the CEPA witness because his average and excess allocation factors are identical to Mr. Oliver's peak and average allocation factors), I again removed the lowest proportionate share of Amtrak's 4CP demand historically provided at Thorndale and Perryville from the peak allocator. I also removed the test year MWH delivered at Thorndale and Perryville from the average demand allocator. This modification to the A.1 allocator resulted in a reduction in the Amtrak revenue requirement of

A. Yes, I have. In my direct testimony at pages 24-27, I addressed PECO's cost allocation study. To the extent that power deliveries at Thorndale and Perryville are included in the 4CP for allocation of production and transmission plant, an over-allocation of demand costs results. Such overstatement of demand costs results in an overstatement of revenue requirement of $5-6 million for Amtrak. For the cost study sponsored by the P.A.I.E.U.G. witnesses, I removed from the 4CP demands used in their A.1 allocator a level of demand which represents the lowest proportionate share of Amtrak's total 4CP demand historically provided at Thorndale and Perryville (i.e. 13,000 KW adjusted for losses). This results in a decrease in the P.A.I.E.U.G. revenue allocation for Amtrak of $4.6 million and a decrease, relative to PECO's proposal, of $4.2 million in the revenues required from Amtrak.

With regard to the peak and average method of cost allocation proposed by the OCA witness (and also apparently by the CEPA witness because his average and excess allocation factors are identical to Mr. Oliver's peak and average allocation factors), I again removed the lowest proportionate share of Amtrak's 4CP demand historically provided at Thorndale and Perryville from the peak allocator. I also removed the test year MWH delivered at Thorndale and Perryville from the average demand allocator. This modification to the A.1 allocator resulted in a reduction in the Amtrak revenue requirement of about $9.4 million relative to that proposed by Mr. Oliver. Adjusted in this manner, Mr. Oliver's revenue requirement from Amtrak is also some $2.4 million less than the revenue level proposed by PECO. I was unable to duplicate the cost study performed by the PBUUG witness. However, I estimate that if Thorndale and Perryville demands were removed from the allocation factors which PBUUG developed for production and transmission plant, the results would fall somewhere between the 4CP and the peak and average results since PBUUG recommends an allocation method which essentially combines both methods.

Q. Are you at this time modifying your position regarding PECO's proposed revenue allocation to SEPTA and Amtrak?

A. No. As stated in my direct testimony, we believe that PECO has treated SEPTA and Amtrak equitably in the allocation of the large rate increase it is requesting in this proceeding. In summary, we wish to note the following at this time:

(1) To date, it appears that no party, including PECO, objects to treating SEPTA and Amtrak as a <u>single</u> separate class of service, as I have proposed in my direct testimony.

(2) PECO, OCA, and PBUUG agree with SEPTA and Amtrak that the traction service customers should pay the system average rate of return.

(3) P.A.I.E.U.G. and UUC/UP propose revenue allocations to SEPTA and Amtrak which would perpetuate past over-allocations of revenues above the cost of service.

(4) Under all the proposed cost of service allocation methods, if power and energy