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January 22, 1986

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SECRETARY'S OFFICE
Public Utility Commission

Mr. Jerry Rich, Secretary
Pennsylvania Public Utility Commission
Room G-18, North Office Building
North and Commonwealth Avenue
Harrisburg, Pennsylvania 17120

Re: Pennsylvania Public Utility Commission, et al. v. Philadelphia Electric Company, Docket No. R-850152

Dear Mr. Rich:

Enclosed for filing with the Commission are the original and three (3) copies of the Testimony and Accompanying Exhibits of Richard J. Rudden (SEPTA-Amtrak Statement 1) and Vukan R. Vuchic, Ph. D. (SEPTA-Amtrak Statement 2), concerning rate structure, on behalf of the Southeastern Pennsylvania Transportation Authority and the National Railroad Passenger Corporation.

Very truly yours,

J. Thomas Morris

JTM/ejz
Enclosures

cc: Honorable Joseph P. Matuschak
Administrative Law Judge
Pennsylvania Public Utility Commission

All parties

DOCUMENT FOLDER

CERTIFICATE OF SERVICE

I hereby certify that I am, this 22nd day of January, 1986 serving either by special messenger or by first-class mail, the Testimony of Richard J. Rudden and Vuckan R. Vuchic, Ph. D. on behalf of Southeastern Pennsylvania Transportation Authority and National Railroad Passenger Corporation, upon the persons listed below:

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SEPTA/Amtrak Statement No. 1

RECEIVED
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SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152

DIRECT TESTIMONY OF RICHARD J. RUDDEN

on behalf of

THE SOUTHEASTERN PENNSYLVANIA TRANSPORTATION AUTHORITY

and

THE NATIONAL RAILROAD PASSENGER CORPORATION

Concerning Rate Structure

DOCUMENT FOLDER

DOCKETED
JAN 23 1986

January 22, 1986

DIRECT TESTIMONY OF
RICHARD J. RUDDEN

Q. Please state your name and business address.

A. My name is Richard J. Rudden. My business address is 425 New York Avenue, Suite 207, Huntington, New York 11743.

Q. By whom are you employed?

A. I am employed by R. J. Rudden Associates, Inc., where I hold the position of President. My firm has been retained by the Southeastern Pennsylvania Transportation Authority (SEPTA) and the National Railroad Passenger Corporation (Amtrak) to assist them in their participation in this proceeding.

Q. Please state your professional and educational background.

A. Since 1967, I have been professionally involved in the fields of utility and regulatory economics, financial analysis and management consulting. Since forming R. J. Rudden Associates in March of 1981, I have provided assistance to utilities, industrial firms, and other clients in the areas of utility revenue requirements, cost analysis, rate design, rate case management, financial feasibility analysis, information systems, strategic planning and related areas.

Prior to forming R. J. Rudden Associates, Inc., I was Vice President and Manager of the Regulation Services Division at Stone & Webster Management Consultants, Inc. While there, I was responsible for client projects relating to gas and electric utility rate design, cost analyses, strategic pricing studies, evaluations of PURPA ratemaking standards, load research and related areas. I also directed, or participated in projects relating to load and sales forecasting, management and regulatory audits, computer system applications, and corporate reorganization. I have published an article on regulatory audits in Public Utilities Fortnightly, have lectured on regulatory economics and practices, and have spoken at a number of utility industry seminars and symposiums.

Prior to joining Stone & Webster in 1975, I was employed in the Rate Engineering Department at Con Edison as a Division Analyst, and was responsible for the administration of the Rate Design Division. My duties included revenue forecasting, tariff administration, the preparation of gas, electric, and steam rate and cost analyses for filings before the New York Public Service Commission, rate design, and the preparation of related testimony. Earlier in my employment at Con Edison, I had technical responsibilities in the areas of power generation, electric distribution network load analysis and special gas and electric market analyses. I was employed by Con Edison between May, 1967 and January, 1975, except for three years during which

I served as a commissioned officer in the U.S. Navy.

I received a Bachelor of Arts degree in Economics from the Queens College of the City University of New York in 1967. In addition, I have completed a major portion of course work in economics and finance towards an MBA at New York University. I am a member of the Rate Committee of the American Gas Association, the Texas Gas Association and the Southern Gas Association. I am also a current member and past Vice-Chairman of the Energy Committee of the Long Island (N.Y.) Association, a regional Chamber of Commerce.

Q. Would you briefly describe your firm?

A. R. J. Rudden Associates, Inc. provides economic, management and financial consulting services to utility and energy companies throughout the United States. We maintain offices in Huntington, New York; Wellesley, Massachusetts; Houston, Texas; and an affiliate office in Arlington, Texas. Our major practice areas include regulatory economics, rate case preparation, planning and forecasting, organizational analysis and management audits, information systems consulting, decision support, alternative energy system evaluations, and project financing analysis. Our clients include electric and gas utilities subject to both FERC and state regulation, energy producers and consumers, other industrial and commercial organizations, financial institutions, and the Canadian government.

Q. Have you testified before this or any other regulatory bodies regarding utility rate design and cost of service?

A. Yes, I have testified before the Connecticut Public Utilities Control Authority (Dockets 761001 and 780402), the Missouri PSC (Case Nos. EO-77-56 and EO-82-40), the Montana PSC (Dockets 6701 and 83.4.21), the Nevada PSC (Docket 83-111), the New Mexico PSC (Dockets 1499, 1568, and 1689), the North Carolina Utilities Commission (Docket No. E-13, Sub 44), and the Pennsylvania PUC (Docket RID 338), and have appeared before the City Council of Garland, Texas. In addition, I have submitted testimony in FERC Docket Nos. ER82-375, RP82-85, and RP84-77.

Q. What is the purpose of your testimony?

A. My purpose is to provide general support for Philadelphia Electric Company's (PECO) proposal to establish separate traction rates for SEPTA and Amtrak; to propose that the Electric Propulsion - SEPTA (EP-S) rate and Electric Propulsion-Amtrak (EP-A) rate filed by PECO in this case be consolidated into a single Electric Propulsion (EP) rate schedule; to propose certain modifications to the billing demands which PECO used to compute the EP-A rate; and to discuss a concern about, and possible modification to, the A.1 allocator used in PECO's class cost of service study as it applies to Amtrak.

Q. Before addressing the above issues, would you please provide a description of the SEPTA/Amtrak system, with particular emphasis on those factors that have a bearing on the nature and costs of electric service provided by PECO?

A. PECO is the major supplier of electricity to Amtrak and the sole direct utility supplier of electricity to SEPTA. As shown on Exhibit RJR-1, the electrified portion of Amtrak runs generally northeasterly from Washington, DC through Philadelphia, and on up to New York. This segment is known as the Northeast Corridor (NEC). In addition, Amtrak has facilities running generally west from Philadelphia to Harrisburg, which is referred to as the Philadelphia-Harrisburg Corridor (PHC).

Along these corridors, Amtrak shares rights of way and facilities with a number of other transit organizations. These include the Maryland Department of Transportation (MDOT), New Jersey Transit, and SEPTA. In many cases, Amtrak redelivers a portion of the electricity it purchases from its electric utility suppliers to the other transit organizations which share its rights of way and facilities. All power utilized on these rights of way and facilities is 25 Hertz (Hz) in frequency. Other than the railroads, there is no other user of, or market for, this 25Hz power.

Of Amtrak's total electrical requirements on the Northeast and Philadelphia - Harrisburg corridors, PECO provides the majority, approximately 80%. Baltimore Gas and Electric provides approximately 16%, and Pennsylvania Power and Light provides the balance, approximately 4%. However, of PECO's 80%, about one-third represents redeliveries of power initially sold to PECO by PP&L and BG&E. Therefore, the portion of Amtrak's total electricity requirements supplied by power actually generated by PECO is more on the order of 50%. The total proportion of power supplied from the generating facilities of PP&L and BG&E is, therefore, correspondingly higher than indicated above. Amtrak, in turn, redelivers about 20-25% of its power to SEPTA. Thus, Amtrak and SEPTA share both rail facilities and electric supply in common, to a significant degree.

Q. Please identify the facilities shared by Amtrak and SEPTA.

A. As shown on Exhibit RJR-1, these facilities run (1) from Philadelphia north to Trenton; (2) from Philadelphia west to Paoli and beyond; and (3) from Philadelphia south to Marcus Hook. In addition, SEPTA operates three of its own branch lines using 25Hz power delivered to it by Amtrak. Finally, SEPTA's line from Philadelphia International Airport to Philadelphia and the line between 30th Street Station and Suburban Station utilize 25Hz power delivered to SEPTA by Amtrak.

Q. Does SEPTA purchase any power directly from PECO?

A. Yes, at 34 delivery points throughout the balance of the SEPTA system. The balance of SEPTA's electrified transportation system includes the former Reading regional rail lines,as well as SEPTA's subway/elevated, trolley and trackless trolley routes in its City Transit and Subway (Red Arrow) Divisions. Exhibit RJR-2 provides a map of the SEPTA system.

Q. In the last several rate proceedings Amtrak and SEPTA have urged PECO to separate them from the HT class for cost analysis and ratemaking purposes. Has PECO done so in this filing?

A. Yes, Mr. Sundermeir's Cost of Service Study calculates costs separately for Amtrak and SEPTA. As I will testify later, the results show that PECO's costs to serve are significantly lower for the traction service customers than for the HT customers. Mr. Williams has proposed separate rate classifications for the two traction customers as a result.

Q. Would you please highlight the facts that support your conclusion that the costs to serve Amtrak and SEPTA are significantly lower than the costs to serve the HT class.

A. Yes. As I will testify, the most significant difference is in the demand costs. According to the results of PECO's cost of service study, the cost per KW of billed demand for the HT customers is $29.22 per KW as compared with SEPTA's $21.54 and

Amtrak's $18.70. Further, as Mr. Sundermeir testified, if they were served under the proposed Rate HT, the rates of return for SEPTA and Amtrak would be 14.36% and 14.15%, respectively, relative to a system wide return of 12.70% and a proposed Rate HT return of 12.23%. This is a good indication of the over recovery of Amtrak's and SEPTA's costs that would result if the traction customers were served under the HT rate.

Q. Do you support PECO's proposal?

A. Yes, in general I support the separate costing and rate treatment for Amtrak and SEPTA proposed by PECO. My testimony adds further justification for separate treatment. I do however, offer some suggestions for the refinement of PECO's proposals. I will also discuss concerns that Amtrak and SEPTA have regarding the determination of Amtrak's coincident peak responsibility.

Q. Would you please describe those characteristics of the Amtrak and SEPTA systems that distinguish these customers from other PECO customers?

A. Yes. It is my opinion that the characteristics I am about to describe make Amtrak and SEPTA unique. Moreover, these characteristics bear directly on the allocation of costs and generally add support to PECO's proposed separate treatment of traction service.

As previously stated, Amtrak redelivers between 20-25% of its total electricity purchases to SEPTA. Consequently, there is a great deal of commonality between SEPTA's and Amtrak's electrical loads and costs, and the demands they place on PECO's system. Thus, any discussion of the character of service of one of the two customers relates to the other. Moreover, Amtrak and SEPTA have distinctive operating characteristics and facility configurations that in my opinion underscore the unique nature of traction service within the PECO service territory.

Q. Please explain.

A. PECO provides power to Amtrak at six points: three within PECO's service territory, at which power is converted through frequency changers from 60Hz to 25Hz; one outside PECO's service territory, at which power is also converted; and two at which power is simply metered as it passes into PECO's service territory from neighboring utilities (or, as is less frequent, it passes from PECO to the neighboring utilities). I will now explain each of these three different groups of delivery points and supply configurations.

The three delivery points that are within PECO's franchise area are Lamokin, Richmond and Somerset. At these points, which are shown on Exhibit RJR-1, PECO converts its standard 60Hz electricity to 25Hz, which Amtrak then receives, transforms as

necessary, and utilizes on its own 138KV transmission system and 12KV catenary system. Once Amtrak takes possession of this electricity, it transmits or uses it along its own right of way, over Amtrak owned and operated transmission facilities. Once PECO delivers this power to Amtrak, PECO incurs no additional cost or obligation for the transmission of the power to those portions of the railroad system where Amtrak uses it.

Metuchen is the delivery point outside of PECO's service territory that is governed by Amtrak's contract with PECO, and at which a frequency changer is located. It is located in New Jersey, approximately half way between Trenton and Newark along the Northeast Corridor. At Metuchen, 60Hz electricity is physically supplied by Public Service Electric and Gas of New Jersey (PSE&G), although it is accounted for as if it were sold by PECO to Amtrak at that point. The 60Hz power is converted to 25Hz through a single 25 MW frequency changer.

Thorndale and Perryville are the two remaining delivery points governed by Amtrak's contract with PECO. Unlike the other four points at which PECO delivers 60Hz power and converts it to 25Hz, Thorndale and Perryville are simply metering points located at the borders between PECO and PP&L (in the former case) and PECO and BG&E (in the latter case.) At these points, 25Hz energy and power are metered as they flow along Amtrak's facilities either into, or out of, PECO's service territory.

Q. Please explain the nature of, and the accounting procedure for, energy and power transactions at Thorndale and Perryville.

A. As stated earlier, electricity is provided to Amtrak by PP&L and BG&E, as well as by PECO. Electricity provided by PP&L and BG&E is generated primarily at the hydroelectric plant owned and operated by Safe Harbor Water Power Corporation which is located on the Susquehanna River in Lancaster County, PA. Safe Harbor is owned jointly by PP&L and BG&E and generates both 60Hz and 25Hz power. The 25Hz power, which is ultimately sold to Amtrak and redelivered in part to SEPTA, is generated by two 25 MW water wheels. Additional 25Hz power can be supplied through a 25 MW frequency changer that converts 60Hz electricity generated at the hydro facility (and elsewhere on the PP&L system) to 25Hz. The frequency changer is also capable of operating in the reverse direction, thereby converting 25Hz power to 60Hz. Except for any 25Hz power that is converted to 60Hz, the only market for the 25Hz output of the plant is Amtrak. In recognition of this, Amtrak is given the contractual right to coordinate the dispatch of the 25Hz power out of Safe Harbor with the railroad's requirements, although in practice there are constraints on this dispatch.

The 25Hz power generated at Safe Harbor is initially delivered to PP&L and BGE at PP&L's Conestoga substation adjacent to the hydro plant. It is then delivered to Amtrak in three ways. Some of the power generated is immediately delivered to Amtrak

by PPL at the Conestoga sub for transmission to, and ultimate use along, the Philadelphia-Harrisburg Corridor. Referring to Exhibit RJR-1, this power is delivered to Amtrak's own 138 KV transmission system, which runs from the Conestoga sub both northwesterly towards Harrisburg and easterly towards Thorndale. This transmission system runs along a section of Amtrak right of way that is not presently used for electric rail transportation, and is maintained by Amtrak exclusively for the purpose of transmitting power from Safe Harbor to the PHC. Any power not used along that portion of the PHC within PP&L's territory is metered at Thorndale, where it is regarded as a delivery by PP&L to PECO under the PJM interchange agreement. Simultaneously, the amount metered at Thorndale is also regarded as a retail sale of power by PECO to Amtrak, under the terms of Amtrak's contract with PECO.

Q. Please explain the second way that 25Hz power generated at Safe Harbor is delivered to Amtrak.

A. Additional 25Hz power generated at Safe Harbor, but not immediately delivered to Amtrak at Conestoga sub, is sent east out of Conestoga to Perryville over transmission lines owned by PP&L. At a point of interchange between PP&L and BG&E (approximately at the Pennsylvania-Maryland border), BG&E picks up the power, continues to transport it, and ultimately delivers it to Amtrak at Perryville. Power so delivered at Perryville is

regarded as a simultaneous interchange delivery by PP&L to BG&E and a retail sale by BG&E to Amtrak. Any power not consumed by Amtrak south of Perryville, but rather that flows north into PECO's service territory is regarded as a simultaneous interchange delivery by BG&E to PECO and a retail sale by PECO to Amtrak.

Q. Please explain the third way that 25HZ power generated at Safe Harbor is delivered to Amtrak.

A. This power is initially delivererd to BG&E at Conestoga sub and then transmitted east for direct sale to Amtrak by BG&E for use by Amtrak generally south of Perryville.

Q. Can power flow from East to West through Thorndale?

A. Yes. In that event the transaction is regarded as a delivery of PJM interchange energy by PECO to PP&L. The energy so flowing is deducted from Amtrak's energy consumption for billing purposes.

Q. Can power flow South through Perryville?

A. Yes. There, the transaction would be a delivery of PJM interchange energy by PECO to BG&E. Energy flowing south is deducted from Amtrak's bill.

Q. Historically, have the net energy flows at Thorndale and Perryville been in a direction into, or out of, the PECO system?

A. The energy flows have been generally into the PECO system, to a significant extent. This is true at the time of PECO's system peak, at the time of each month that Amtrak establishes its peak billing demand, over the entire month, and over the entire year.

Q. On what information do you base this statement?

A. I base my statement on the data shown in PECO's response to IR-SEPTA/Amtrak-1-17(Revised), and to DR-WFS8-SEPTA/Amtrak (1/6/86). I have consolidated this information into Exhibit RJR-3.

Q. What does Exhibit RJR-3 show?

A. Exhibit RJR-3 shows that over the time periods for which data were available, energy and power delivered at Thorndale and Perryville provided:

1. Nearly 38% of Amtrak's total energy (MWH) requirements;
2. About 21% of the demand for which Amtrak was billed; and
3. Approximately 32% of Amtrak's requirements at the time of PECO's four system peaks.

Q. What is your conclusion?

A. My conclusion is that historically, Amtrak has received a significant portion of both its energy and power requirements from sources other than PECO. Moreover, since energy delivered to PECO at Thorndale and Perryville is transmitted over Amtrak transmission facilities, Amtrak: (1) comprises an integral part of the PJM pool, (2) provides substantial amounts of net energy to PECO from the PJM pool, (3) facilitates the operation of the PJM pool, and (4) as a consequence, provides a significant benefit to PECO and PJM. However, Amtrak receives no direct compensation for this service from either PECO or PJM.

Q. Does Amtrak receive any non-monetary benefit from its involvement in the PJM system?

A. Yes, the benefit is obtained in the form of diversity of supply, and therefore increased reliability of power. As an integral part of PJM, it can and does receive power from PECO, PP&L and BG&E.

Q. Does Amtrak pay for any of these benefits?

A. Yes. Amtrak makes substantial separate payments to its suppliers, over and above the rates charged to it under each supplier's standard tariff for the purchase of power. These payments are to cover the costs of: (1) the operation and maintenance of PP&L's 132,000 volt transmission line running between Conestoga Sub and the Maryland-Pennsylvania border and

between Conestoga Sub and the Maryland-Pennsylvania border and other related lines and facilities; (2) the costs of transmission and related facilities interconnecting PECO with PSE&G and Metuchen; (3) the operating and maintenance costs associated with the frequency changers at Metuchen, Richmond, Somerset and Lamokin; and (4) the costs of facilities operated by BG&E on behalf of Amtrak. These specific facilities charges total more than $2.5 million a year. In addition, Amtrak also pays for any capital improvement to facilities directly serving Amtrak.

Q. Does Amtrak's diversity of supply also provide benefits to PECO?

A. Yes. To the extent power is available from these other sources, it is less likely that PECO will have to supply, from PECO's own generation and transmission facilities, Amtrak's full requirements at or near the time of PECO's system peak. Moreover, as a member of PJM, PECO benefits from the economics of pooled dispatch. Since Amtrak facilities enhance the interchange of economic pooled power, it stands to reason that PECO and its customers benefit from Amtrak's role.

Q. Please explain how these matters relate to SEPTA.

A. Many of these issues affect the allocation of costs to Amtrak, and therefore the rates charged to Amtrak. Since Amtrak redelivers between 20-25% of its electricity to SEPTA, any change in electricity costs to Amtrak resulting from the

disposition of these issues will directly affect SEPTA's bill for electricity.

Q. What other factors make electrical service to Amtrak and SEPTA unique?

A. There are a number of factors which, when taken in their totality, make SEPTA and Amtrak very different from other customers. Although any one or two of these factors may be similar to the characteristics of other customers on the PECO system, it is my opinion that when all of Amtrak and SEPTA's use, service and facilities characteristics are considered together, these two customers indeed stand out from all other PECO customers.

First, both SEPTA and Amtrak are very large customers, both individually and collectively. Combined, they purchase about 700 million kwh per year, and provide in excess of $56 million a year in revenue, excluding ECR revenues. These two customers account for about 2.5% of PECO's total system - wide sales.

Secondly, both customers exhibit distinct and systematic twin peak daily load patterns, with very high peaks relative to most other customers in both the morning and evening. Further, they are generally winter-peaking customers.

Thirdly, while other customers may have multiple delivery points as do Amtrak and SEPTA, none have as many (40 points combined) over the wide geographic area as do SEPTA and Amtrak, nor is the mode of delivery as complex as described previously, especially for Amtrak.

Fourth, as previously discussed, many of the facilities that service Amtrak and SEPTA are large, dedicated and unique, and costly to maintain. These dedicated facilities are either paid for directly by Amtrak, or owned by SEPTA.

Finally, to complete the description of the differences between Amtrak/SEPTA and other customers, we must reiterate and add to the list above, the items from my previous testimony. These are:

1. The uniqueness of 25Hz power to traction use.
2. The dispatching of Safe Harbor power by Amtrak.
3. The integral physical part that Amtrak plays in PJM.
4. The pool benefits that Amtrak provides, and the benefits it receives, through parallel operation with PECO and other utilities.
5. The back up to PECO capacity that Amtrak provides through the availability of PP&L and BG&E power at the time of PECO's peak.

Q. Do all of these differences actually result in differences in the costs of service between Amtrak/SEPTA and other customers?

A. Yes. The most relevant comparison for the purpose of demonstrating this would be between the railroads and the HT class, since the HT class contains customers who are perhaps the most nearly comparable to the railroads, and since the HT rate is the rate under which Amtrak and SEPTA are presently served.

Based on Mr. Sundermeir's cost of service study, the customer costs per delivery point per month for Amtrak and SEPTA are $1,583 and $1,279, respectively, as compared with $268 for customers in the HT class. There is clearly a significant difference in the customer cost of service between the traction service customers and the average HT customer.

Turning to demand-related costs, Mr. Sundermeir's study shows that the average cost per billed KW for the HT class is $29.22 per KW. (This would be somewhat higher if Mr. Sundermeir had imputed the higher system-wide average return of 12.70% that Amtrak and SEPTA would pay under the proposed rates, instead of the lower 12.23% that the HT class is being asked to pay.) The comparable demand cost per billed KW for SEPTA is $21.54, and for Amtrak it is $23.16. Thus, the cost per KW of billed demand for HT customers is 36% higher than for SEPTA, and 26% higher than for Amtrak. Later in my testimony, I will address my

proposal for certain justified modifications to the demand billing determinants used in computing Amtrak's rates. Should these modifications be adopted, Amtrak's demand-related costs per billing KW would be even lower relative to the HT demand costs. In fact, based on the results of PECO's cost of service study, they would drop to $18.70 per KW, and the HT unit cost would then be 56% higher than Amtrak's cost.

Q. What is your conclusion regarding PECO's proposal to break out the traction loads from the HT class?

A. My conclusion is that it is appropriate and desirable to do so. The separation of traction loads is justified by the significant differences that exist between the HT class and the railroads in their operation, end-use and cost characteristics.

Q. What would be the consequence if the PUC were to disapprove PECO's proposal to separate the traction loads from the HT class?

A. In my opinion, that would result in a highly inequitable situation. As previously shown, the proposed HT class rates are based on costs that are, overall, substantially higher than the costs to serve SEPTA and Amtrak. To require these two customers to receive continuing service under the HT rate, in the face of the cost evidence submitted by PECO and my earlier testimony, would be inappropriate.

Q. Do you support PECO's proposal in its entirety?

A. I support it to the extent that it gives traction loads separate cost and ratemaking treatment. However, I do not support the proposition that there should be separate EP-A and EP-S rates. I support and propose a consolidated EP rate.

Q. Please explain why.

A. Ratemaking theory generally prescribes the grouping of customers with similar end-use, load and cost characteristics into separate rate classes. This argues for the separation of traction loads from the HT class into a separate class. It does not, however, support the creation of two separate traction classes. While there are significant differences between traction and other HT loads, there are compelling similiarities between the end-use, load and cost characteristics of SEPTA and Amtrak. Briefly, these similarities are:

1) Joint use of facilities.
2) Redelivery of energy from Amtrak to SEPTA and a significant sharing of energy costs.
3) Similar load profiles.
4) Identical end-use (i.e., passenger electric traction).
5) Similar cost characteristics.
6) Nature of electricity used (25Hz).

Q. Would a consolidation of the proposed EP-A and EP-S rate schedules result in any change to the revenues required from any other class?

A. No. A consolidation would affect only Amtrak and SEPTA. There would be no revenue or rate impact on other customers.

Q. Earlier, you indicated that the diversity of electricity supply to Amtrak provided benefits to PECO, in that it reduced the chances that PECO would have to supply all of Amtrak's requirements at the time of PECO's system peak. Would you please elaborate?

A. Amtrak tends to peak one to two hours, and sometimes more, after the time of PECO's system peak. Consequently, Amtrak already provides some diversity benefit to PECO. In addition to this benefit, however, Amtrak provides "back-up" through the availability of power from PP&L and BG&E at the time of PECO's peak. Should PECO experience difficulties in meeting peak load for any reason, or experience more localized distribution problems affecting the three on-system frequency changers, Amtrak could call on power out of Safe Harbor, or from BG&E out of the Benning Sub (shown on Exhibit RJR-1), to relieve the PECO problem. This is a benefit to PECO and its customers that is real, albeit difficult to quantify.

Q. Could this supply diversity benefit have any bearing on Mr. Sundermeir's cost of service study?

A. Yes. When Mr. Sundermeir allocated production and transmission costs to Amtrak, he used a 4CP allocator (allocation factor A.1.) that included the demands registered at Thorndale and Perryville. In other words, he used the 52,707 KW registered at all six delivery points in 1984, as shown on Exhibit RJR-3, and adjusted that number for losses, to arrive at the 56,249 KW shown under Amtrak's A.1 allocation on page 29 of Exhibit WFS-1.

Q. In your opinion, was that entirely appropriate?

A. No. It does not provide credit for the benefits conveyed by Amtrak, and its back-up power supplies, to PECO. The allocation methodology results in Amtrak being assigned costs as if all the power delivered at Thorndale and Perryville were supplied by PECO production and transmission facilities, when it appears from the historical data available and contained in Exhibit RJR-3 that PECO has never supplied all of Amtrak's requirements at the time of PECO's four system peaks. In fact, demands at Thorndale and Perryville have provided, on average, 32% of Amtrak's requirements at the time of PECO's system peak, as shown on Exhibit RJR-3.

Q. What were the actual Thorndale and Perryville contributions to the four coincident peaks in the allocation used by Mr. Sundermeir?

A. They were 26,750 KW, or about one half of Amtrak's 4CP responsibility.

Q. Would you suggest completely removing the Thorndale and Perryville demands from Amtrak's 4CP responsibility ?

A. No, not completely, although some downward adjustment may be appropriate. The present A.1 factor allocates too much demand cost to Amtrak. The 4CP demands could be reduced by a reasonable and conservative amount to reflect the minimum contributions that Thorndale and Perryville have made historically to PECO's four coincident peaks. Based on the data shown on Exhibit RJR-3, this minimum contribution could be regarded as the lesser of: (1) the lowest absolute KW contribution to the 4CPs made at Thorndale and Perryville, which is about 16,000 KW; or (2) the lowest proportionate share of Amtrak's total 4CP that has been historically delivered at Thorndale and Perryville, applied to Amtrak's total test year 4CP contribution. This latter approach would yield a Thorndale and Perryville contribution of approximately 13,000 KW (24.5% multiplied by 52,707 KW). The use of either of these two numbers could result in a significant reduction in Amtrak's revenue requirements, and ultimately in electricity costs to both Amtrak and SEPTA.

Q. Have you estimated the amount by which Amtrak's revenue requirement could be reduced by such an adjustment?

A. Yes. Under the most conservative case, Amtrak's revenue requirement could be reduced by about $5 million. Under the second case, the reduction could be approximately $6 million. If Thorndale and Perryville demands were eliminated from the test year altogether, the reduction would be about $10 million.

Q. How do you recommend the Commission resolve this issue of the Thorndale and Perryville demands as related to Amtrak's 4CP responsibility?

A. Before responding directly, I would like to state that SEPTA and Amtrak are, at this time, reserving judgment on the overall issue of revenue requirements in this case, and on the impact the resolution of this issue may have on the allocation of the rate increase to the customer classes. SEPTA and Amtrak are also of the opinion that, in general, they have received reasonable treatment by PECO in this case with respect to the proposed creation of separate traction rates, the allocation of costs, and the design of rates. The major exceptions to this statement are that: (1) Amtrak/SEPTA strongly prefer a single consolidated traction, or Electric Propulsion (EP), rate; and (2) Amtrak/SEPTA are concerned that the Thorndale and Perryville demands have been incorrectly treated in the development of the 4CP allocator, resulting in a significant over allocation of

demand costs to Amtrak in the order of approximately $5-6 million.

SEPTA and Amtrak understand the practical limitations that both the PUC and Company face in equitably distributing to all of PECO's customers the large rate increase that PECO is requesting in this case, and resolving the multitude of complex issues presented. At this point we are not requesting any specific reduction in the revenues PECO proposes to recover from Amtrak and SEPTA. We are, however, requesting the parties to this case, the Administrative Law Judge, and the Commission to take note of our disagreement with PECO on the matter of the inclusion of 100% of the Thorndale and Perryville concident peak demands in the A.1 allocator. In addition, should the Commission modify PECO's total revenue requirements, its cost allocation methodology, or the formula used for distributing the final rate increase in any way that adversely affects SEPTA and Amtrak relative to their present position, Amtrak and SEPTA reserve the right to use the Thorndale and Perryville 4CP demand issue in establishing their new position.

Q. At the beginning of your testimony you indicated that you are proposing to modify the billing demands that PECO has used to compute the EP-A rate. Please explain.

A. Unlike the issue of the inclusion or exclusion of Thorndale and Perryville demands in the computation of the 4CP allocator,

which affects the total demand costs allocated to Amtrak, the matter of billing demands affects only the number of billing units over which the costs allocated to Amtrak will be recovered. This has a direct effect on the computation of the unit demand rate, i.e., the cost per KW billed to Amtrak. Given a fixed level of demand costs to be recovered, the unit rate per billing KW will be lower if a higher number of billing KW are assumed in the test period. Conversely, the unit rate will be higher if lower billing KW are assumed.

A new contract between Amtrak and PECO became effective in January, 1984. The major change to the contract was to exclude from Amtrak's billing demands the demands recorded at Thorndale and Perryville. PECO has reflected this contract modification in the billing demands used in this rate case to compute the proposed EP-A rates, and the revenues the proposed EP-A rates would produce in the test period.

Pursuant to recent conversations between PECO and Amtrak, the two companies have entered into a stipulation, shown as Exhibit RJR-4, that they agree to modify the existing contract to include the demands at Thorndale and Perryville in the determination of Amtrak's billing demand. Accordingly, I am proposing to increase the test year billing demands for Amtrak to reflect this stipulation. It is our understanding that PECO is agreeable to this, and will modify its filing in this regard.

Q. What is the result of doing this?

A. Based on information provided to me by PECO, the result is to increase Amtrak's billing demand from 1,068,926 KW to 1,324,000 KW, reflecting the addition of 255,074 KW of billing demands at Thorndale and Perryville.

Q. Have you designed a consolidated EP rate?

A. Yes. I have prepared Exhibit RJR-5 which shows the EP rate that SEPTA and Amtrak are proposing. It is simply a consolidation of PECO's proposed EP-S and EP-A rate schedules. This rate assumes: (1) the revenues produced by the EP rates will be approximately the same as the sum total of the revenues produced by PECO's proposed EP-A and EP-S rates; and (2) the demands metered at Thorndale and Perryville are included in the billing determinants, as stipulated between PECO and Amtrak.

Q. Do you propose the Commission adopt the EP rate?

A. Yes, provided the Commission grants PECO the revenue increase that it has requested. Should the Commission grant PECO some lesser amount of rate relief, we would ask for an opportunity to provide our comments on cost allocation and rate design before the Commission renders its final decision.

Q. Do you have any comments regarding the wording of the proposed EP-A, EP-S and EP Tariffs?

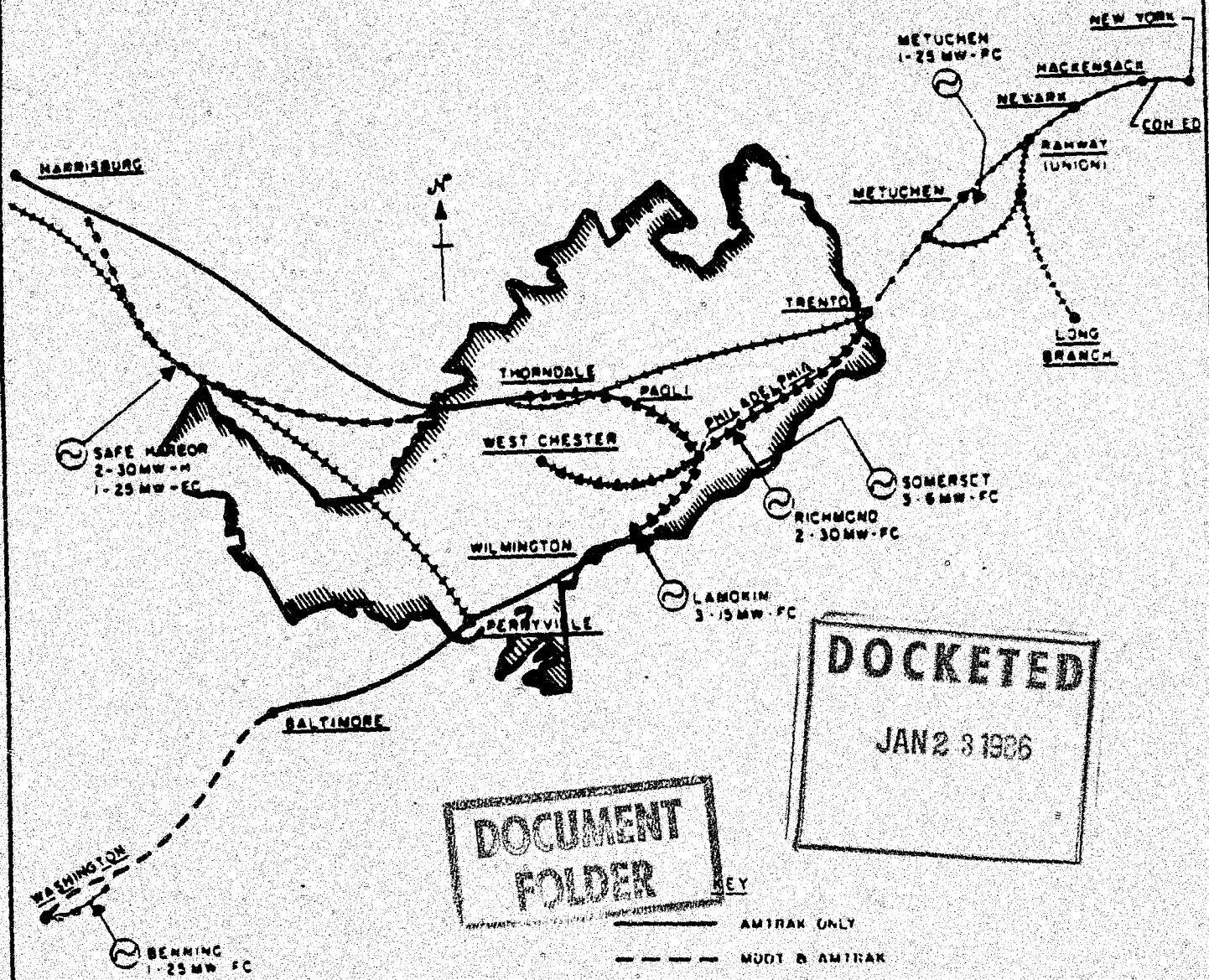
A. Yes. There was some confusion over the wording of the "Delivery Points" section of the EP-S tariff. To clarify the matter, I am proposing the modifications and wording shown on Exhibit RJR-6. These modifications also address changes that would be necessary upon a consolidation of the proposed EP-A and EP-S rate schedules into a general EP rate.

Q. Does this complete your testimony?

A. Yes, it does.

SEPTA/AMTRAK FACILITIES

RELATIVE TO PE Co SERVICE AREA



DOCKETED
JAN 23 1986

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KEY

- AMTRAK ONLY
- MDOT & AMTRAK
- NJ TRANSIT ONLY
- NJ TRANSIT & AMTRAK
- SEPTA ONLY
- SEPTA & AMTRAK
- NOT IN USE FOR ELECTRIC OPERATION
- OVERBUILD RETAINED FOR SUPPLY PURPOSES (TRACKS NOT IN USE FOR ELECTRIC OPERATION)
- APPROXIMATE PE Co SERVICE AREA

Exhibit RJR-2

SEPTA MAP

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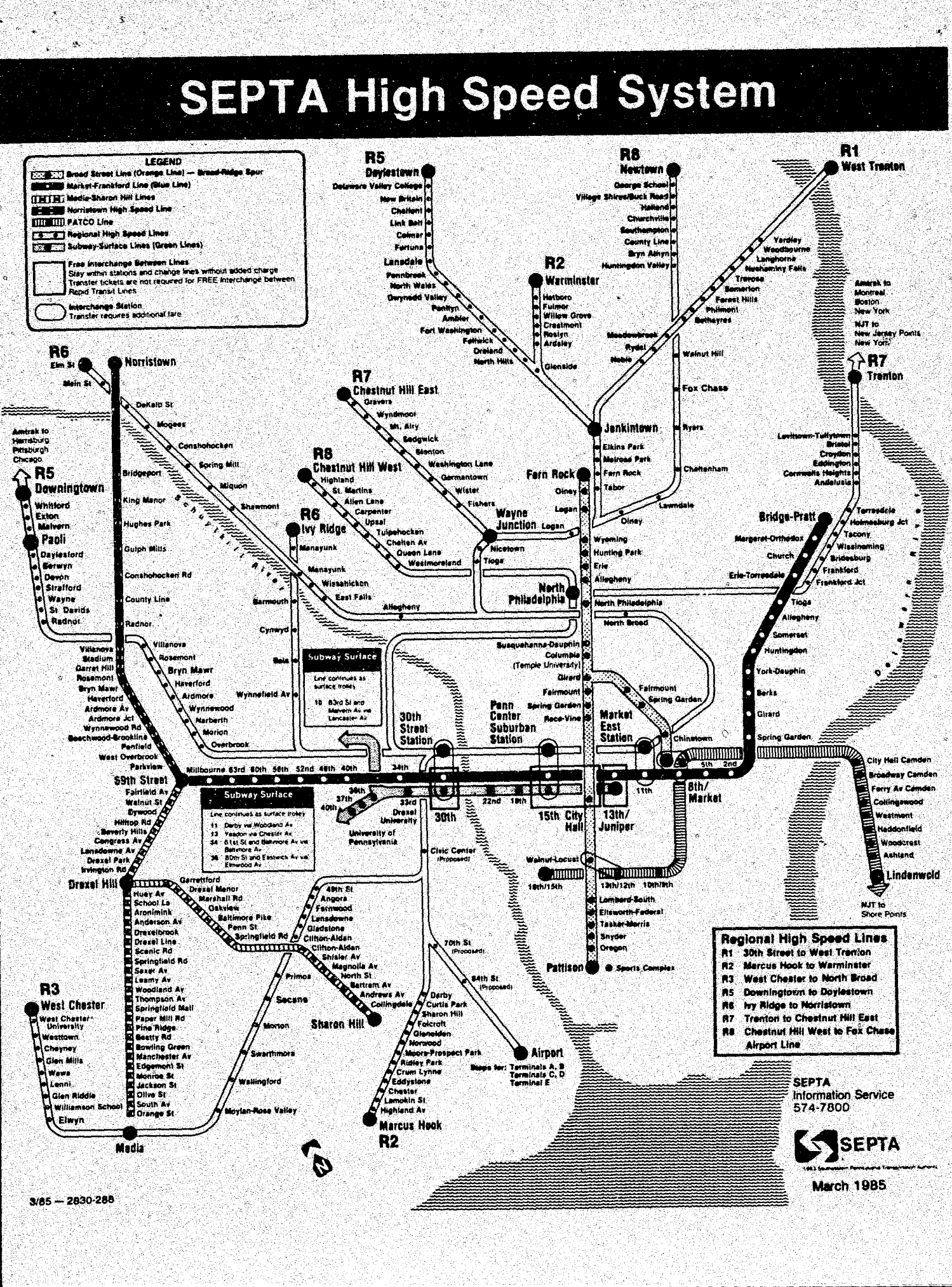
JAN 2 3 1996

SEPTA High Speed System



3/85 — 2630-288

Exhibit RJR-3

Summary of Energy and Demands Recorded at Thorndale & Perryville

Megawatt Hours (MWH)

Year	Thorndale & Perryville	Total Amtrak	Percent that Thorndale and Perryville are of total
1982	161,707	411,205	39.3%
1983	158,864	388,909	40.8
1984	175,071	423,336	41.4
3 Year Total	495,642	1,223,450	40.5
11 Mos. Ending 11/85	119,124	405,362	29.4
Total, All Information	614,766	1,628,812	37.7%

Billing Demand (KW)

1982	260,000	1,279,984	20.3%
1983	234,000	1,196,382	19.6
1984	330,000	1,413,526	23.3
3 Year Total*	824,000	3,889,892	21.2%

Contribution to System 4CP(KW)

1981	16,500	66,135	24.9%
1982	23,000	71,059	32.4
1983	16,333	66,673	24.5
1984	26,750	52,707	50.8
3 Year Total	66,083	190,439	34.7%
Total, All Information	82,583	256,574	32.2%

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* Complete 1985 data for billing demands are not available.

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Exhibit RJR-4

STIPULATION

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DOCKETED
JAN 23 1986

Amtrak®

January 21, 1986

Mr. Raymond C. Williams,
Manager, Rate Division
Philadelphia Electric Company
230 Market Street
Philadelphia, Pennsylvania 19109

Re: Electric Traction Contract

Dear Mr. Williams:

The purpose of this letter is to amend the agreement between the parties, dated January 1, 1984, for Electric Service and Maintenance and Operation of Frequency Conversion Facilities for Railroad Traction Service (hereafter the Agreement) coincident with a possible change in the Philadelphia Electric Company (PE) tariff applicable to Amtrak's purchase of electric power from PE. The revised tariff has been proposed by PE in a proceeding that is currently pending before the Pennsylvania Public Utilities Commission.

The parties hereby agree to revise Paragraph 10 of the Agreement in its entirety to read as follows:

"10. Determination of Billing Kilowatts and Kilowatts Hours

The monthly billing demand of Amtrak shall be the greatest sum of the coincidental 30-minute demands measured at the Lamokin, Richmond, Somerset, Metuchen, Perryville, and Thorndale delivery and metering points, adjusted for the power factor and not less than 49,000 kilowatts.

The monthly billing kilowatt hours of Amtrak shall be the sum of the kilowatt hours measured at the Lamokin, Richmond, Somerset, Metuchen, Perryville, and Thorndale delivery and metering points. For the purpose of billing, meter registrations indicating energy flows north at Perryville and east at Thorndale will be deemed positive, and meter registrations indicating energy flows south at Perryville and west at Thorndale will be deemed negative."

This agreement to revise Paragraph 10 of the Agreement shall take effect only in the event a new tariff is adopted by the PUC which establishes a separate rate for Amtrak (either individually or jointly with SEPTA) and is based on inclusion of the units of billed demand metered at Perryville and Thorndale in the determination of the unit demand charges payable by Amtrak. If such a new tariff is adopted, this amendment shall be effective on the effective date of the new tariff.

In consideration hereof, PE agrees to modify the rates contained in its currently proposed EP-A tariff to reflect the inclusion of the units of billed demand metered at Perryville and Thorndale in the determination of the proposed unit demand charges payable by Amtrak.

Please have a duly authorized representative of PE sign the extra copy of this letter that is enclosed in the space indicated below in order to reflect PE's agreement to this revision.

Sincerely,

D. F. Sullivan
Vice President
Operations and Maintenance

Concurrence:

_____ Date: _____

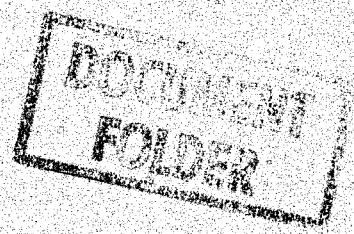
Exhibit RJR-5

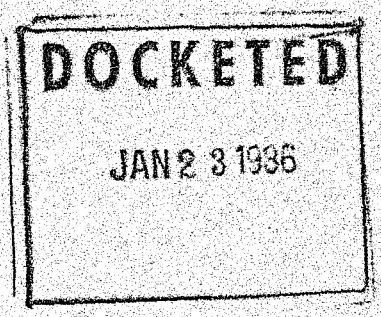
SEPTA/Amtrak Proposed EP Rate

(A Consolidation of PECO's Proposed EP-A and EP-S Rate Schedules)

Monthly Rate Table

Service Charge:	$1,354.00 per delivery point.
Capacity Charge:	$14.22 per KW.
Energy Charge:	3.75¢ per KWH.





See Exhibit RJR-6 for suggested modifications to tariff wording.

Exhibit RJR-6

Proposed Modifications to the Language
of the EP-A and EP-S Tariffs

1. Add to Determination of Billing Demand "....For the portion of the Southeastern Pennsylvania Transportation Authority (SEPTA) operating on the rights-of-way of the former Reading system, the billing demand shall be calculated as if delivered at a single point, designated SEPTA-Reading, regardless of the number of points of actual delivery. For all other service delivered for the operation of other portions of SEPTA transit system, the billing demand shall be calculated as if delivered at a second single point designated SEPTA-Transit."

2. Revise and combine "DELIVERY POINTS" to read: "As set forth in separate agreements with AMTRAK and SEPTA."

3. Revise and combine "AVAILABILITY" clause to provide traction service to AMTRAK and SEPTA.

4. Revise and combine "TERM OF CONTRACT" clause to read: "As set forth in separate agreements with AMTRAK and SEPTA."

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DOCKETED
JAN 2 3 1986

SEPTA/Amtrak Statement No. 2

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

RECEIVED
JAN22 1986
SECRETARY'S OFFICE
Public Utility Commission

DOCKET NO. R-850152

DIRECT TESTIMONY OF VUKAN R. VUCHIC, Ph.D.

on behalf of

THE SOUTHEASTERN PENNSYLVANIA TRANSPORTATION AUTHORITY

and

THE NATIONAL RAILROAD PASSENGER CORPORATION

Concerning Rate Structure

DOCUMENT FOLDER

January 22, 1986

DOCKETED
JAN 23 1986

DIRECT TESTIMONY OF
VUKAN R. VUCHIC, Ph.D.

Q: Please state your name and position.

A: I am Dr. Vukan R. Vuchic. I am a Professor of Civil Engineering - Transportation at the University of Pennsylvania.

Q: Please summarize your educational and professional experience in the area of public transportation.

A: I have a diploma from the University of Belgrade, and a Masters degree in Engineering and Ph.D. from the University of California in Transportation Engineering. Most of my academic and professional work has been in urban transportation, particularly public and rail transportation. I have published approximately 80 articles, reports and sections of books in the United States and other countries. My book Urban Public Transportation Systems and Technology, published in 1981, is the only comprehensive book on that subject published in several decades. I have served as a consultant on the planning of rail transit in many cities, including San Francisco, Caracas, Venezuela, and Edmonton, Canada. I have lectured at about 40 universities on several continents. In addition, I have testified before several committees of the United States Congress and before the Pennsylvania Public Utilities Commission in R-842590. My resume is attached as Exhibit VRV-1.

Q: What is the purpose of your testimony?

A: I will testify concerning the indispensable role of SEPTA and Amtrak in the society, economy and environment of southeastern Pennsylvania, the adverse effects on the society, economy, and environment which would occur if the operations of SEPTA and Amtrak were curtailed, and the reasons supporting separate rate classification for these transit companies.

Q: Please summarize your conclusions.

A: 1. SEPTA and Amtrak provide an indispensable service to the citizens, the economy and environment of Philadelphia and the surrounding region. In particular, the electrically-powered transit systems operated by SEPTA and Amtrak offer transportation services in a heavily populated urban area which cannot feasibly be provided by any other means. Moreover, SEPTA and Amtrak serve many people who have no other means of transportation.

2. Public transportation companies such as Amtrak and SEPTA have unique characteristics and financial problems as compared to other institutions that provide public services. Their special importance and particular needs have long been recognized by governmental policy.

3. Sound public policy dictates that the unique and important role of public transportation systems be recognized in the electric rates charged to these customers.

Q: Could you describe the role that public transportation has played in the society, economy and environment of southeastern Pennsylvania?

A: In very few cities has development been as clearly linked with the development of public transportation as is the case with Philadelphia and its suburbs. The highest concentration of all activities -- commercial, governmental, retail, cultural, and tourist -- is found in Philadelphia's central business district, which is the hub of all public transportation services.

Recently, most of the office development in Philadelphia (Penn Center, Center Square, Reading One and others), as well as retail complexes (the two Galleries), would not have taken place had there been no improvement in the transit services in these areas, such as modernization of subways and construction of the regional rail system's Center City Commuter Tunnel.

Historically, a number of major activity centers within the City of Philadelphia and its suburban areas were created or their development intensified by their close connection with transit stations and terminals. Examples of this are Bridge Street and Olney in Philadelphia, and such areas as 69th Street in Upper Darby, Lansdowne, Swarthmore, Bryn Mawr, Ardmore, and Jenkintown in the suburbs. It should be noted that in all of these instances <u>electric</u> transit has been a major influence on the region's development and urban form.

Q: Could you briefly describe the role that SEPTA and Amtrak play today as providers of mass transportation service in southeastern Pennsylvania?

A: Together, SEPTA and Amtrak provide a variety of electric transportation services in and through southeastern Pennsylvania. SEPTA's regional rail, subway/elevated rapid transit and subway-surface trolley lines provide one of the most basic services which an efficient urban area must have: virtually ubiquitous transportation at all hours when reasonable demand exists, at prices acceptable to most people. Similarly, Amtrak's inter-urban services represent a basic means of travel in the most populated corridor in the country, of which Philadelphia is one of the largest parts.

Q: Are there feasible alternatives to a public transportation system, such as that provided by Amtrak and SEPTA, in the Philadelphia area?

A: No. A comparison of mass transit with alternative modes of travel gives a good indication of the significance and indispensability of mass transit. If the present transit travel were replaced, even in part, by private automobiles, adverse consequences would follow. The capacity of the expressway/street system would become inadequate in all areas of major concentrations of activities. Extensive congestion would result and existing parking facilities would be grossly inadequate. Moreover, about 30% of families in the city do not own cars; a substantial portion are not licensed drivers. Many of these people would be deprived of

convenient transportation absent SEPTA's and Amtrak's electric transit services.

Q: Which population groups are most affected by reductions in the quantity and/or quality of transit services and by increased fares?

A: While transit in Philadelphia is used by all economic groups, low income groups particularly depend on SEPTA's services. More than 50% of SEPTA riders who purchase TransPasses (i.e. passes which permit unlimited rides during a certain period) have annual incomes of less than $15,000. The fact that transit disproportionately benefits low income groups is one of the rationales for supporting public funding of mass transit.

Q: Has the importance of the public services provided by mass transportation systems been recognized by governmental policy?

A: Since electric transit was invented near the end of the 19th century, its vital role for cities has been recognized in a number of governmental policies and legislation, from federal to local levels. For instance, it was the City of Philadelphia which built the Broad Street Subway and leased it to the Philadelphia Rapid Transit Company and to its successor, the Philadelphia Transportation Company, and since 1968, to SEPTA.

The Pennsylvania Legislature has recognized the importance of public transportation through enactment of the Metropolitan Transportation Authorities Act of 1963, SEPTA's original enabling legislation, and that Act's successor, enacted in 1980 -- the Pennsylvania Urban Mass Transportation Law. One of the findings of the Pennsylvania General Assembly in the Urban Mass Transportation Law was that "efficient and coordinated urban common carrier mass transportation systems, facilities and services will promote the public health, safety, convenience and welfare."

The role of long-distance public transportation, part of which is now performed by Amtrak today, has always been considered to be an essential service for the country and for the cities and regions it serves, and it too has been supported by government in various forms.

A recent and relevant example of support for long-distance transit is the statement of "Congressional Findings and Declaration of Purpose" in the Rail Passenger Service Act of 1970 which established Amtrak. There, Congress found "that the public convenience and necessity require that the National Railroad Passenger Corporation provide, to the extent that the Corporation's budget allows, modern, cost-efficient, and energy-efficient intercity railroad passenger service between crowded urban areas and in other parts of the country [and] that rail passenger service can help in alleviating the overcrowding of airways, airports, and

highways." Congress further found that "modern, efficient commuter rail passenger service is important to the viability and well-being of major urban areas and to the national goals of energy conservation and self-sufficiency."

Q: Although SEPTA and Amtrak provide an important public service, should they receive treatment any different from the treatment afforded other customers that provide public services such as airports, the Navy Yard, the city water department, or private industries in the region?

A: Yes, they should. Public transportation services are <u>not</u> the same as many other urban services. Public transportation has a distinct combination of characteristics which render it quite unique among other urban services. Those characteristics are relevant to the issue being discussed here.

First, public transportation is one of the basic services which affect many aspects of the society, economy and environment. Besides its obvious and essential contribution in transporting people from place to place, mass transit provides significant indirect benefits to the community. Examples of such indirect benefits include increased mobility, which is important for lower unemployment; improved health care and educational opportunities; the availability of a broader geographical area from which skilled and unskilled labor can be drawn; and a more livable urban

environment. For this reason, a region with good transit, such as Philadelphia, has major advantages over regions with poor transit. By the same token, curtailment of mass transit can deprive people of education, health service and jobs.

Second, raising additional revenue for mass transit is extremely difficult because increasing transit fares results in serious problems. Most notably, ridership drops, decreasing some of the revenue gains. In some cases, the additional revenue generated by raising fares may not be worth the increase because of the significant demand elasticity for transit use. Moreover, some of the passengers shift to driving their automobiles. This produces a "Catch 22" situation which would ultimately result in curtailment of essential services, thus affecting the remaining passengers, and a loss of the direct and indirect benefits which flow from a fully operational system. Not only are these benefits lost, but the increased driving by former transit riders negatively affects other automobile drivers, as well as the entire urban environment.

Q: Do not other facilities, such as the airport or the Navy Yard, have problems comparable to those of SEPTA and Amtrak?

A: No, the problems of public transit companies are distinguishable. Taking the airport as one example, the differences can be summarized as follows:

(1) For numerous reasons, the funds to finance airports are more readily available than funds to finance transit. Available sources of investment and operating funds for airports are more adequate than those for SEPTA and Amtrak.

(2) Electricity is a much less essential element of an airport's operation than it is in the operation of SEPTA and Amtrak;

(3) Demand for air travel is less elastic (and particularly insensitive to electric rates) than is the demand for electric public transportation; and

(4) Air travellers represent, on the average, a considerably higher than average income segment of the population, while the opposite is generally true for the riders of SEPTA and Amtrak.

Q: What are the implications for public policy if SEPTA and Amtrak are paying disproportionately more for traction power than the cost of serving them?

A: It is clearly in the public interest that public transportation in the Philadelphia metropolitan area -- both intraurban and interurban -- be maintained and improved. To achieve this goal, public policy should encourage and create conditions favorable for maintenance and modernization of transit facilities. Public policy should support increased use of electric traction

power and assist SEPTA and Amtrak in achieving their maximum economic efficiency and in reducing their reliance on uncertain governmental financial assistance. If it is the case that SEPTA and Amtrak pay disproportionately more for propulsion power than the cost of providing that service, these policy goals are being defeated. Electric rates that closely reflect the costs incurred by PECO would produce widespread benefits to transit riders and the Philadelphia area in general.

Q: In its present rate filing, PECO has proposed separate rate classification for SEPTA and Amtrak under which SEPTA and Amtrak will pay the system average rate of return based on a cost of service study for these customers by PECO. Do you agree with separate rate classification for SEPTA and Amtrak?

A: Yes. As discussed above, public transportation systems, such as those operated by SEPTA and Amtrak, play a unique and important role in the society and economy of southeastern Pennsylvania. Sound public policy dictates that this unique and important role be reflected in a separate electric rate reflecting the lower costs of serving these companies, as discussed in the testimony of Richard J. Rudden and as evidenced in PECO's cost of service study.

Q: Does that conclude your testimony?

A: Yes.

VUKAN R. VUCHIC

1. Personal

1.1 Born: 1935 in Belgrade, Yugoslavia.
1.2 Immigrated in 1961; U.S. citizen since 1968.
1.3 Married, four children.

2. Education

2.1 Diploma in Transportation and Traffic Engineering - University of Belgrade, Yugoslavia, 1960.

2.2 M.Eng. in Civil Engineering - Transportation - I.T.T.E., University of California, Berkeley, 1965.

2.3 Ph.D. in Engineering - Transportation - I.T.T.E., University of California, 1966.

2.4 Languages: English, German, Russian and Serbo-Croatian (mother tongue).

3. Academic Appointments

3.1 University of California, School of Business Administration, Berkeley - 1966, Acting Assistant Professor.

3.2 University of Pennsylvania - 1967, Assistant Professor; 1970, Associate Professor; 1975, Professor of Civil Engineering - Transportation (present position).

4. Professional Experience

4.1 Hamburger Hochbahn AG (Public Transport Co.), Hamburg, Germany, 1960-1961, Planning Engineer.

4.2 Wilbur Smith & Associates, Consulting Engineers, New Haven, CT, 1961-63 and in San Francisco part-time 1964-65, Principal Engineer.

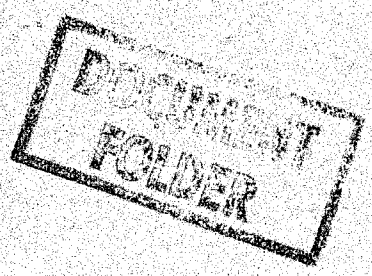
4.3 University of California, College of Engineering, Operations Research Center, Berkeley, 1966, Junior Specialist.

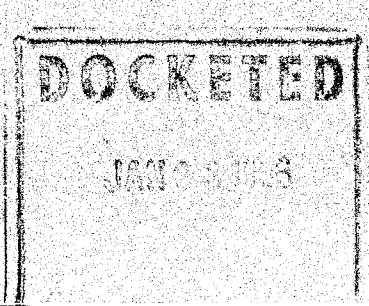
5. Consulting Activities

5.1 Wurster, Bernardi & Emmons, Consulting Architects; San Francisco, 1964-66.

5.2 Lawrence Halprin and Associates, Landscape Architects; San Francisco, 1965-66.

5.3 Wallace Holm Associates, Consulting Architects; Monterey, California, 1966.





5.4 Wilbur Smith & Associates, Consulting Engineers, Washington, 1967.

5.5 David A. Crane, Urban Planning and Design; Philadelphia, 1967-68.

5.6 Dechert, Price and Rhoads, Attorneys; Philadelphia, 1969-70.

5.7 Turnpike Engineers, Inc., Consulting Engineers; Philadelphia, 1970.

5.8 University City Science Center; Philadelphia, 1971.

5.9 Vincent Kling Associates, Consulting Architects; Philadelphia, 1972-76.

5.10 Transportation Systems Center, U.S. D.O.T., Cambridge, MA 1971-72.

5.11 Township of Middletown, PA, 1972-80.

5.12 Interplan Corporation, Consulting Planners; Santa Barbara, CA, 1971-75.

5.13 MITRE Corporation; McLean, VA, 1974.

5.14 Office of Technology Assessment, U.S. Congress; Washington, 1975.

5.15 Urban Mass Transportation Administration (U.M.T.A.), D.O.T., Washington, 1975-77.

5.16 DeLeuw, Cather and Co., Consulting Engineers, Washington, 1975-77.

5.17 Township of Springfield, PA, 1978-79.

5.18 Venturi and Rauch, Architects and Planners, Philadelphia, PA, 1978-79.

5.19 Mattioni, Mattioni, & Mattioni, Attorneys, Philadelphia, PA, 1979-81.

5.20 Gellman Associates, Consultants, Philadelphia, PA, 1979.

5.21 City of Philadelphia, Mayor's Office, 1980.

5.22 Boston College, School of Education, on UMTA-sponsored project about assisting rail transit use by the blind, 1980-81.

5.23 City of Edmonton, Alberta, Canada; member of a 3-person international team of consultants for light rail transit network planning, 1982.

5.24 Systema Transporte Regional, Caracas, Venezuela, 1981-82.

5.25 Cambridge Systematics, Cambridge, MA, 1981-83.

5.26 Bruinette, Kruger, Stoffberg, Pretoria, South Africa, 1982-83.

5.27 Southeastern Pennsylvania Transportation Authority - SEPTA, Philadelphia, PA, 1983-85.

5.28 Certainteed Corporation, Tredyffrin, PA, 1984.

5.29 William T. Coleman, Jr. (on Thompson-Coleman's report on SEPTA's Regional High Speed Lines), 1985.

5.30 Westinghouse Electric Corporation, Pittsburgh, 1985.

6. Professional and Honorary Societies

6.1 Association of Transportation Engineers and Technicians of Yugoslavia, Belgrade, Yugoslavia - Member (since 1959).

6.2 International Union of Public Transport, Brussels, Belgium - Personal Associate Member (1962).

6.3 Institute of Transportation Engineers, Washington - Member (1965). Member of three technical committees (1968, 1970, 1980); Assistant Chairman, Planning Applications Division (1971/72).

6.4 Chi Epsilon.

6.5 Operations Research Society of America - Member (1976-80); Transportation Science Section Council Member (1969/70).

6.6 Transportation Research Board - Representative of the University of Pennsylvania (1968). Member of several committees; chairman of the Rail Transit Committee 1977-83.

6.7 American Society of Civil Engineers, New York City - Member (1971).

6.8 Theodore M. Matson Memorial Corporation - Member (1972).

6.9 Transportation Subcommittee, Mayor's Science and Technology Advisory Committee, Philadelphia, Vice-Chairman (1972-80).

7. Awards

7.1 Award for high academic grade score; University of Belgrade, Yugoslavia, 1960.

7.2 Automotive Safety Foundation Fellowship for Doctoral Studies, University of California, Berkeley, 1964/65 and 1965/66.

7.3 M.S. honoris causa - University of Pennsylvania, Philadelphia, 1971.

7.4 Co-recipient of the 1980 Urban Design Administration Honor Award given by the Department of Housing and Urban Development for a project on Old City renovation in Philadelphia (as consultant to Venturi & Rauch).

7.5 Recipient of the first "Dr. Friedrich Lehner Medal", given by the "Dr. Friedrich Lehner Stiftung (Endowment)" in Hannover, F.R. Germany, to "persons who have dedicated a life work to urban public transportation and excelled in that effort"; received in Munich, 15 June 1982.

8. Publications - Books

8-A Gray and Hoel (Editors), Public Transportation: Planning, Operations and Management (Vuchic author of two chapters); Prentice Hall, 1979.

8-B Urban Public Transportation Systems and Technology; Prentice Hall, Inc., 1981, 673 pages.

Publications - Articles

8.1 "Some Remarks about the Traffic Regulation in W. Germany and Denmark" - Transportation 2/1959, pp. 317-319 (in Serbian, summary in German).

8.2 "Highway and Urban Traffic in Great Britain" - Transportation 5/1959, pp. 866-871 (in Serbian, summary in English).

8.3 Review of the book: H. K. Evans (Editor): "Traffic Engineering Handbook" - Transportation 10/1959, p. 1660 (Serbian).

8.4 "Public Transportation in London" - Urban Transportation 10-11/1959 pp. 11-30 (Serbian). Also published with modifications, in Transportation 1/1961, pp. 154-161 (Serbian, summary in English).

8.5 "Development of Road Networks in Scandinavian Countries" Transportation 4/1960, pp. 824-828 (Serbian, summary in English).

8.6 Review of the book: W.W. Hay: "Railroad Engineering" - Transportation 4/1960, p. 832 (Serbian).

8.7 Review of the Road Research Laboratory (England) reports: "Road Research in 1956" and "Road Research in 1957" - Transportation, 4/1960, pp. 832-833 (Serbian).

8.8 Review of the book: Baker and Funaro: "Parking" - Transportation 8/1960, p. 1602 (Serbian).

8.9 "Traffic Signals" - Transportation 6/1961, pp. 1115-1123 (Serbian, summary in German).

8.10 "Role of Public Transportation in Hamburg, Germany - Traffic Quarterly, January 1964, pp. 118-140.

8.11 Discussion on the paper "Airport Accessibility Affects Passenger Development" in the Journal of the Aero-Space Transport Division, Proceedings of the ASCE, 1/1966.

8.12 "Pedestrian Crossing Time in Determining Widths of Signalized Traffic Arterials" - Transportation Science, Vol. 1, No. 3, Aug. 1967, pp. 224-231.

8.13 (with Gordon F. Newell)* "Rapid Transit Interstation Spacings for Minimum Travel Time" - Transportation Science Vol. 2, No. 4, December, 1968, pp. 303-339.

8.14 "Fahrplanstorungen - zusatzliche Faktoren, betriebliche Massnahmen" - Verkehr und Technik Vol. 22, No. 4, April 1969, pp. 97-100.

8.15 "Propagation of Schedule Disturbances in Line-haul Passenger Transportation" (in French, English and German) - Revue de l'UITP, No. 4, 1969; Brussels, Belgium (an expanded version of paper #8.14).

8.16 "Rapid Transit Interstation Spacings for Maximum Number of Passengers" - Transportation Science Vol. 3, No. 3, August 1969, pp. 214-232.

8.17 "A System View at the Urban Highway Transportation Situation" - Proceedings of the Pennsylvania Highway Transportation Conference, Pennsylvania State University, 1969.

8.18 "Minicar Transit System - A New Concept and Its Evaluation" - Highway Research Record 318, pp. 27-39; Washington 1970.

8.19 (with Wolfgang S. Homburger) "Federation of Transit Agencies as a Solution for Service Integration" - Traffic Quarterly, July 1970, pp. 373-391.

8.20 "Concept of Flexibility in Transportation System Analysis" - High Speed Ground Transportation Journal Vol. 5, No. 1, 1971, pp. 53-61.

8.21 (with Bernard F. Byrne): "Public Transportation Line Positions and Headways for Minimum Cost"; in Traffic Flow and Transportation; Editor: G.F. Newell; American Elsevier, 1972, pp. 347-360.

8.22 (with Wolfgang S. Homburger): "Transit Federation - A Solution for Service Integration"; (in French, English and German) - Revue de l'UITP No. 2, 1972, pp. 73-100; Brussels, Belgium (an updated version of paper #8.19).

8.23 (with Richard M. Stanger)*: "Lindenwold Rail Line and Shirley Busway - A Comparison"; Highway Research Record 459, pp. 13-28; Washington, 1973.

8.24 (with Michael J. Weston)*: "Urban Transportation Improvements Through Low Cost Traffic Engineering Measures"; Highway Research Record 461, pp. 30-24, Washington, 1973.

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*Vuchic principal author.

8.25 "Skip-Stop Operation as a Method for Transit Speed Increase"; Traffic Quarterly, April 1973, pp. 307-327.

8.26 Discussions of Reports 3a, 3b, and 6; Proceedings of the 39th UITP Congress in The Hague; UITP, Brussels, 1973.

8.27 "Quo Vadis, ASCE?"; Civil Engineering, June 1973, pp. 59-61.

8.28 "Rapid Transit Automation and the Last Crew Member"; Railway Gazette International, October 1973, pp. 382-385; London, England.

8.29 (with S. Kikuchi)*: "Design of Outlying Rapid Transit Station Areas"; TRB Record 505, 1974, pp. 1-12.

8.30 (with E. Tennyson and W. Underwood)*: "Application of Guidelines for Improvement of Transit Service and Operating Efficiency"; TRB Record 519, 1974 pp. 66-72.

8.31 "National Transportation Policy - The Basic Prerequisite for Progress"; Hearings, Subcommittee of the Committee on Appropriations, U.S. House of Representatives; Part I, pp. 217-253. U.S.G.P.O. Washington, 1974.

8.32 (with R. Stanger)*: "New Transit Technologies: An Objective Analysis is Overdue"; Railway Gazette International, October 1974, pp. 384 - 387; London, England.

8.33 (with B. Day and R. Stanger)*: "Rail Transit: Characteristics, Innovations and Trends"; TRB Record 552, pp. 1-18, 1975.

8.34 (with B. Day)*: "Some Comments on Bus Capacity Analysis" - Discussion of a paper by Levinson/Hoey; TRB Record 546, pp. 41-42, 1975.

8.35 Discussion of a paper by Boyd, et al.; TRB Record 559, pp. 45-47, 1976.

8.36 "Comparative Analysis and Selection of Transit Modes"; TRB Record 559, pp. 51-62, 1976.

8.37 "Schnellbahn Automation und "der Letzte Mann" am Zug"; translation of #8.28; Verkehr und Technik, March 1975, pp. 90-94.

8.38 "Urban Transportation Policy: Time for Reorientation"; written testimony to the Transportation Committee of the National Conference of Democratic Mayors; New Orleans, 22 March 1975.

8.39 "Place of Light Rail in the Family of Transit Modes";TRB Special Report 161, pp. 62-76, 1975. Also published in Saobracaj u gradovima (in Serbian); Belgrade, 1977.

8.40 (with B. Day and B. Anderson)*: "Theoretical and Practical Capacities of Transit Modes" - presented at the Intersociety Conference of Transportation, Atlanta, 1975.

8.41 "Evaluating UMTA's Work" - Proceedings of the R & D Priorities Conference, DOT/UMTA with APTA, Washington, February 1976, pp. 97-99.

8.42 "Skip-Stop Operation: High Speed with Good Area Coverage" (in French, English and German), UITP Revue, No. 2, Brussels, 1976.

8.43 "Transit Regulation: Improve It, or Eliminate It?" - Transit Journal November 1976, pp. 5-14. Also published in: Urban Transportation Economics, TRB Special Report 181, 1978, pp. 76-79.

8.44 Discussions of Reports 3a, 4 and 8; Proceedings of the 41st UITP Congress in Montreal; UITP, Brussels, 1977.

8.45 "Rail Transit in Perspective" - Rail Transit Conference of APTA, Washington, June 1977.

8.46 "Heavy Obstacles for Light Rail"; Highlights from the presentation of the paper #8.49; Railway Age, 12 September 1977, pp. 62-63.

8.47 "Which Mode can Save Most Energy? No Simple Answer Exists", written testimony for the Senate Committee on Environment and Public Works, 5 October 1977.

8.48 "Integrated Urban Transportation - A Major Challenge for Transportation Engineers", Proceedings of the 47th Annual Meeting of the Institute of Transportation Engineers, Mexico City, October 1977.

8.49 "Current Trends: Problems and Prospects of Light-Rail Transit"; TRB Special Report 182, "Light-Rail Transit: Planning and Technology"; pp. 8-12, 1978.

8.50 "Die Bedeutung des offentlichen Nahverkehrs aus Nordamerikanischer Sicht"; Schriftenreihe fur Verkehr und Technik, Heft 67, pp. 76-100; Bielefeld, W. Germany, 1978.

8.51 "Light Rail Transit in Boston - Symbol of a New Era"; Proceedings of the International Symposium "Roads in Towns", sponsored by Asahi Shimbun, Tokyo, 16-18 May 1979; pp. 17-1 to 17-18. Also published in Japanese translation of the Proceedings, pp. 17-1 to 17-12.

8.52 (with R.M. Stanger), "The Design of Bus-Rail Transit Facilities"; Transit Journal, APTA, Washington, Fall 1979, pp. 61-72.

8.53 "High-Performance Transit Planning, Modes and Networks"; Proceedings of Mass Rapid Transit System Seminar; Taipei, Taiwan, December 1980; pp. 17-72.

8.54 "Designers Widen the Urban Rail Options" - Railway Gazette International, January 1982, (4 pp.), London, England.

8.55 (with S. Kikuchi), "Transit Vehicle Stopping Regimes and Spacings" - Transportation Science, Vol. 16, No. 3, August 1982, pp. 311-331.

8.56 "Javni gradski promet: sistemi i tehnologija" (adapted sections from Vuchic's book, #8-B); Suvremeni promet 3/1982, pp. 239-243; Zagreb, Yugoslavia.

8.57 "Transportation Technologies for Cities in Developing Countries" - paper in English, French and Spanish, presented at CODATU II Conference, Caracas, Venezuela, October 1982.

8.58 (with T.J. Potter)* "Train Crew Reduction for Increased Productivity of Rail Transit"; TRB Record 980, pp. 51-57, 1983.

8.59 "Analytical Review of Guided Transit Systems"; Proceedings of the Conference on Advanced Rapid Transit Systems, held in Amalfi, Italy, October 1983 (in preparation).

8.60 "The Auto Versus Transit Controversy: Toward a Rational Synthesis of Urban Transportation Policy"; Transportation Research Special Issue on Public Policy; Vol. 18A, No. 2, Spring 1984.

8.61 "Transit Technology Today"; Proceedings, Symposium on Recent Developments of Urban Transit Technology, pp. A-1 - A-30; November 1984, Taipei.

8.62 "O-Bahn - Description and Evaluation of a New Concept"; TR Record 1011, pp. 8-15, Washington, 1985.

8.63 (with R.M. Stanger) "Automated Guided Transit versus Conventional Rail"; TR News 120, Sep.-Oct. 1985, pp. 8-13; Washington.

8.64 "Light rail transit - Ugly duckling becomes a swan"; Railway Gazette International 11/1985, pp. 829-835; London.

8.65 (with S. Kikuchi) "Planning an Integrated Regional Rail Network: the Philadelphia Case"; TR Record (in preparation); Washington, 1985.

8.66 "Spurgefuhrter Bus - Auswertung eines neuen Konzepts"; Der Nahverkehr (in preparation).

9. Published Reports and Manuals

9.1 Interstations Spacings for Line-haul Passenger Transportation; report of the Operations Research Center, University of California, Berkeley, to the National Bureau of Standards, 1966; 144 pages.

9.2 (with David E. Boyce), A Critique of the D.V.R.P.C. 1985 Regional Transportation Plan; University of Pennsylvania, October 1969; 19 pages.

9.3 (Editor and co-author), Minicar Transit Systems - Final Report of the multidisciplinary research group, University of Pennsylvania, to UMTA - U.S. Department of Transportation; September 1970; 274 pages.

9.4 Value of Speed in Public Transit Services; Transportation Studies Center, University of Pennsylvania, 1970; 57 pages.

9.5 Light Rail Transit Systems - A Definition and Evaluation; report to UMTA through the Transportation Systems Center, Cambridge, MA, 1972; 111 pages.

9.6 (with S. Kikuchi)* Design of Outlying Rapid Transit Stations - report to UMTA - U.S. Department of Transportation; NTIS, Springfield, Virginia, 1973; report PB 223279, 52 pages.

9.7 Integration of Transit Systems - report UMTA RI-06-0005-73-3 by Interplan Corporation, Vuchic co-author; 4 volumes; NTIS, Springfield, Virginia, June 1973.

9.8 (As panel member): Automated Guideway Transit; O.T.A. - U.S. Congress, 1975.

9.9 Light Rail Transit--A State-of-the-Art Review - report to UMTA-DOT by De Leuw, Cather & Company, Vuchic consultant; 1976.

9.10 Transit Operating Manual; Pennsylvania DOT, 1976; second edition, 1978; 220 pages.

9.11 Land Use Impacts of Rapid Transit: Implications of Recent Experience; report by DeLeuw, Cather & Company to the Department of Transportation; Vuchic consultant; August 1977.

9.12 (with S. Hessami)*, Parking Policy as a Transportation System Management Measure; report to UMTA-U.S.D.O.T.; NTIS, Springfield, Virginia, 1978; 67 pages.

9.13 Report on Interstate 476; Congressman Edgar's Transportation Advisory Committee (Vuchic Chairman); February 1979; 51 pages.

9.14 Timed Transfer Systems Planning, Design and Operation; Report to UMTA; program report DOT-I-83-28; 124 pages.

9.15 Train Crew Reduction for Increased Productivity of Rail Transit; report to UMTA - U.S. DOT; NTIS, Springfield, Virginia, 1982; 86 pages.

9.16 DeLeuw, Cather & Company; Light Rail Transit: Surface Operations (a report; b. Technical Appendix); Vuchic co-author. Report to UMTA/DOT-IT-06-0103; Washington, 1981.

9.17 (with H. Felz and D. Howard), South Edmonton Light Rail Transit Plan Review; report to the City of Edmonton, Canada, April 1982; 46 pages.

9.18 Levinson and Weant (Editors), Urban Transportation Perspectives and Prospects (includes an adapted version of paper #8.29 by Vuchic and Kikuchi, pp. 275-281); Eno Foundation, Westport, CT, 1982.

9.19 Transportation in Philadelphia; report of the Task Force on Transportation, co-chaired by Vuchic and W.B. Allen, part of the study "Philadelphia Past, Present and Future", 1982; (Vuchic wrote a section on Passenger Transportation, 29 pages).

9.20 (with S. Kikuchi)*, General Operations Plan for the SEPTA Regional High Speed System; report to SEPTA, Philadelphia, PA, 1984; 220pp.

9.21 Contributor to the "Report on the Regional High Speed Lines" by Thompson and Coleman, submitted to SEPTA, Philadelphia, 1985.

10. Presentations

a. Major Seminars

10a-1 Sole lecturer at a one-day seminar on "Transit Planning" organized by the Ministry of Transport, Province of Ontario, Toronto, 6 May 1975.

10a-2 "Mass Rapid Transit Planning Seminar", organized by the Taiwan Ministry of Communications, Taipei, 9-11 December 1980; Vuchic one of the five invited speakers.

10a-3 Sole lecturer at a one-day seminar on "Urban Transportation Issues and Policies" in the Department of Transportation, Republic of South Africa; Pretoria, 3 August 1981.

10a-4 Transit Policy Planning, Management and Operation", course for SEPTA Management Personnel; Vuchic organizer and principal lecturer (32 out of 44 hours). The course given at the University of Pennsylvania, Philadelphia, PA, Fall 1980 and Spring 1982.

10a-5 Sole lecturer of a 3-day continuing education course on "Urban Public Transport Planning", University of Stellenbosch, 13-15 July 1983.

10a-6 "Light Rail Transit" - one-day seminar organized by BKS, Pretoria, 1 August 1983.

10a-7 Five lectures in a 4-day "Seminar on Guided Transit Systems" organized by COVITUR, Mexico, 24-27 October 1983.

b. Testimonies

10b-1 Hearings on the National Transportation Policy; Transportation Subcommittee of the Committee of Appropriations, U.S. House of Representatives; Washington, 6 March 1974 (#8.31).

10b-2 Hearings on the National Urban Transportation Policy; Transportation Committee, National Conference of Democratic Mayors, New Orleans, 22 March 1975 (#8.38).

10b-3 Hearings on the 1975 Highway Federal Aid Act, Transportation Subcommittee, Public Works Committee, U.S. House of Representatives, Washington, 8 September 1975.

10b-4 "Let Us Treat Transportation as a Coordinated System"; testimony to the Subcommittee on Surface Transportation, House Committee on Public Works and Transportation; U.S. House of Representatives; Washington, 15 July 1981.

c. Presentations at Professional Societies, Meetings, Lectures in Major Transportation Agencies

10c-1 Association of Transport Engineers and Technicians of Yugoslavia (DITJ), Belgrade, 1960, 1970, 1976.

10c-2 Operations Research Society of America (ORSA): New York 1967, Miami Beach 1969, Detroit 1970, Atlantic City 1972.

10c-3 Institute of Engineering Education (IEE): Andover, NH, 1967.

10c-4 Hamburger Hochbahn AG, Hamburg: 1968, 1971.

10c-5 Transportation Research Board (TRB): 1970, 1973, 1974 (2), 1975 (3), 1976, 1977, 1980 (2), 1981, 1983.

10c-6 Regional Science Association of America (RSA): Philadelphia 1972, 1985.

10c-7 International Union of Public Transport (UITP): The Hague 1973, Montreal 1977.

10c-8 Caltrans' course "Public Transportation State-of-the-Art": Sacramento 1974, San Diego 1974, San Mateo 1975.

10c-9 American Public Transit Association (APTA): New York 1974, Washington 1977, Philadelphia 1981, San Diego 1983.

10c-10 Engineering Society of Detroit: 1975.

10c-11 American Society of Civil Engineers (ASCE), Philadelphia Section: 1975, 1983.

10c-12 Urban Mass Transportation Administration (UMTA): R&D Conferences in Washington, 1976 (2); TTS Conference in Portland, OR 1983.

10c-13 German Scientific Transport Association (DVWG): Hamburg 1976.

10c-14 Institute of Transportation Engineers (ITE): Mexico 1977.

10c-15 German Association of Transit Agencies (VOV): Frankfurt 1978, Munich 1982.

10c-16 Oahu Development Conference, Honolulu: 1978.

10c-17 International Conference on Urban Transport organized by Asahi Shimbun: Tokyo 1979.

10c-18 Teito Rapid Transit Authority (TRTA), Tokyo: 1979.

10c-19 International Association of Traffic and Safety Sciences (IATSS), Tokyo: 1979.

10c-20 Northeast-Midwest Coalition, U.S. Congress: 1979.

10c-21 Chartered Institute of Transport: Cape Town 1981.

10c-22 International Center for Transportation Studies (ICTS): Amalfi, Italy, 1983.

10c-23 Symposium on Recent Developments of Urban Transit Technology, Keynote speech: "Transit Technology Today" (#8.61); Taipei, 27-29 November 1984.

10c-24 China Road Federation Annual Meeting, Keynote speech: "Present and Future of Highway Transportation"; Taipei, 30 November 1984.

11. Invited Lectures at Universities

11.1 University of Belgrade, Faculty of Transportation and Traffic Engineering: invited lecturer in the graduate program (16 hrs.- in Serbo-Croatian); December 1970.

11.2 University of Zagreb, Faculty of Civil Engineering: "Trends in Urban Transportation Systems Development" (in Serbo-Croatian); 21 December 1970.

11.3 University of Pennsylvania, Towne School, Colloquium on Urbanism: "Urban Transportation in Future Perspective"; Philadelphia, 3 March 1971.

11.4 Southern Illinois University: "Planning and Environment - A Comparative Review of European and American Approaches"; Carbondale, IL, 2 June 1971.

11.5 Technische Universitat Munchen, Department of Transportation Engineering and City Planning: "Urban Transportation Models and Technologies in the United States" (in German); 15 June 1972.

11.6 University of Salford, Department of Civil Engineering: "Light Rail Transit Systems"; Salford, England, 21 June 1972.

11.7 Pennsylvania State University, Transportation and Safety Center: "Urban Transportation Modes: Characteristics, Relationships and Optimal Domains"; State College, PA; 11 January 1973.

11.8 Ohio State University, Department of Civil Engineering: "Comparative Analysis of Transportation Modes"; Columbus, OH; 22 February 1973.

11.9 Temple University: "Urban Transportation Systems: New Technology"; Philadelphia, 13 and 15 March 1973.

11.10 Technische Universitat Munchen, Department of Transportation Engineering and City Planning: "New Transportation Systems: Real Potential or Misdirection?" (in German); 24 May 1973.

11.11 Carnegie-Mellon University, Pittsburgh - Professional Program in Urban Transportation; lecturer on topics: transit scheduling, rail and bus transit, comparative analysis of modes; 3-7 hrs. each year, 1973-1979.

11.12 Ohio State University, Department of Civil Engineering: "Toward Formation of Urban Transportation Systems"; Columbus, OH, 13 November 1973.

11.13 University of California - ITS, "Comparative Analysis of Transit Modes"; Berkeley, 27 March 1974.

11.14 Princeton University, Department of Civil Engineering: "Automated Transit Systems"; November 1974.

11.15 University of Wisconsin, Seminar on Light Rail Transit; speaker at two sessions; Milwaukee, 25-26 April 1975.

11.16 University of Pennsylvania, Department of Civil and Urban Engineering, "Society, Professionals and Academia"; Herbert Spencer Lecture Series; Philadelphia, 11 December 1975.

11.17 University of Hawaii, Department of Civil Engineering, with Oahu Development Conference: "Urban Design and Transportation Planning"; Honolulu, 4 January 1978.

11.18 Universitat Karlsruhe, Institut fur Wirtschaftspolitik und Wirtschaftsforschung: "Methodology for Comparison of Transit Modes" (in German); 16 June 1978.

11.19 Portland State University, School of Urban Affairs, keynote speaker at the Workshop on Light Rail Transit; Portland, OR; 14 September 1978.

11.20 Universidad Simon Bolivar, Department of Civil Engineering, a series of lectures (10 hrs.) in the Graduate Seminar on Urban Transportation Planning; Caracas, 2-6 October 1978.

11.21 Georgia Institute of Technology, School of Civil Engineering, "Family of Transit Modes: Definitions and Characteristics"; Atlanta, 19 April 1979.

11.22 University of Tokyo, Department of Civil Engineering, "Trends in Rail Transit"; 24 May 1979. Also three lectures in an undergraduate course, 4-6 June 1979.

11.23 University of Hokkaido, Department of Civil Engineering, "Interchange Design"; Sapporo, 28 May 1979.

11.24 Tokyo Institute of Technology, Department of Social Engineering, "Trends in Rail Transit", 31 May 1979.

11.25 University of Kobe, Department of Civil Engineering, "Trends in Rail Transit", 18 June 1979.

11.26 University of Kyoto, Department of Civil Engineering, "Trends in Rail Transit", 19 June 1979.

11.27 Taiwan Technical University and Transportation Planning Board, "Urban Transportation Trends: Theoretical Analyses and Practical Policies". Taipei, 26 June 1979.

11.28 Dartmouth College, Thayer School of Engineering, "Urban Transportation Policies under Prospects of Limited Energy"; Charles C. Jones Seminar Series, Andover, NH, 4 October 1979.

11.29 Polytechnic Institute of New York, Department of Transportation Planning and Engineering, "Present and Future Role of Transit in U.S. Cities"; Seminar Series in Transportation, New York, 20 February 1980.

11.30 Villanova University, Department of Civil Engineering, "Definitions and Characteristics of Urban Transportation Modes"; Philadelphia, 26 February 1980.

11.31 Massachusetts Institute of Technology, Center for Transportation Studies, "Are Current Urban Transportation Policies Responsive to the Needs of Our Cities?"; Cambridge, MA, 19 September 1980.

11.32 National University of Taiwan, Department of Civil Engineering, "Trends in Rail Transit"; Taipei, 12 December 1980.

11.33 University of Alberta, Light Rail Transit Study Program, lectures on LRT Network Planning, Infrastructure and Rolling Stock (4 hrs.); Edmonton, Alberta, Canada, 25-26 May 1981.

11.34 University of Calgary, Department of Civil Engineering, "Urban Transportation Developments in the Light of Environmental and Energy Aspects"; Calgary, Alberta, Canada, 27 May 1981.

11.35 University of Stellenbosch, Department of Civil Engineering, as visiting Professor, lectured courses on urban public transportation; Stellenbosch, South Africa, 20 July - 12 August 1981, 18 May - 12 June 1982 and 18 July - 9 August 1983.

11.36 University of Belgrade, Faculty of Transportation Engineering, "Trends in and Relationships Among Urban Transportation Modes" (in Serbian); 26 August 1981.

11.37 Instituto Politecnico Nacional, Division de Ciencias Sociales, three lectures in the area of Urban Transportation; Mexico City, 21-23 September 1981.

11.38 Universidad Central, Department of Civil Engineering, "Rail Transit Systems Design and Operation"; (5 lectures); Caracas, 23-27 November 1981.

11.39 Drexel University, Department of Civil Engineering, "Public Transportation"; Philadelphia, 1 Dec. 1982, 8 Mar. 1983 and 5 Mar. 1984.

11.40 University of Michigan, Transportation Center, "Technological Innovations and Their Impact on Transit Role in Cities"; Ann Arbor, MI, 11 February 1983.

11.41 University of Orange Free State, Department of Urban Planning, "The Role of Public Transportation in City Planning"; Bloemfontain, South Africa, 9 August 1983.

11.42 University of Virginia, Department of Civil Engineering, "Urban Form and Transportation: Recent Experiences"; Charlottesville, Va, 22 March 1984.

11.43 University of Delaware, Department of Civil Engineering, "Auto vs. Transit Controversy in Urban Transportation"; Newark, DE, 4 Nov. 1985.

12. Research Projects

Sponsored research obtained from:

-Department of Housing and Urban Development;
-Urban Mass Transportation Administration;
-Department of Transportation,Office of the Secretary;
-Pennsylvania Science and Engineering Foundation;
-Pennsylvania Department of Transportation
-New York City Transit Authority;
-Southeastern Pennsylvania Transportation Authority.

December 1985

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GILBERT NURICK
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JEFFERSON C. BARNHART

January 22, 1986

Re: Pennsylvania Public Utility Commission, et al.,
v. Philadelphia Electric Company
Docket No. R-850152

DOCUMENT FOLDER

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JAN 22 1986
SECRETARY'S OFFICE
Public Utility Commission

Jerry Rich, Secretary
Pennsylvania Public Utility Commission
New Filing Section
Room B-18 - North Office Building
P. O. Box 3265
Harrisburg, PA 17120

Dear Secretary Rich:

Enclosed for filing with the Commission please find the original and nine (9) copies each of the testimony of Dr. Melvin P. Bloom and Jeffry Pollock of Drazen-Brubaker & Associates, Inc. on behalf of the Philadelphia Area Industrial Energy Users Group in the above-captioned proceeding.

Dr. Bloom and Mr. Pollock will be available for cross-examination on February 19 and/or 20, 1986 at hearings to be conducted in Philadelphia.

All parties of record have been provided with copies as evidenced by the attached Certificate of Service.

Very truly yours,

McNEES, WALLACE & NURICK

By David M. Kleppinger
David M. Kleppinger

DMK/jf
Enclosures
HAND DELIVERED
cc: All Parties of Record (w/encl.)

CERTIFICATE OF SERVICE

Pennsylvania Public Utility Commission, et al., : Docket No. R-850152
v. :
Philadelphia Electric Company :

I hereby certify that I have served a copy of the foregoing document on all known parties of record to this proceeding, all by first class mail (unless otherwise indicated) properly addressed as follows:

** Administrative Law Judge
Joseph P. Matuschak
PA Public Utility Commission
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David M. Kleppinger

Dated this 22nd day of JANUARY, 1986, at Harrisburg, PA.

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JAN 2 8
SECRETARY'S OFFICE
PUBLIC SERVICE COMMISSION

Before the

Public Service Commission of Kentucky

Frankfort, Kentucky

In the Matter of:

Testimony and Exhibit

of

Kevin D. Dragon

On Behalf of the

Philadelphia Area Industrial Energy Users Group

(A Trade Association Representing the Views of Certain Large Industrial Energy Consumers)

The Boeing Company

Ford Motor Company

Gulf Oil Corporation

Lukens Steel Company

Nabisco Brands, Inc.

SKF (A Burroughs Company)

Smith Kline Beckman Corporation

Sun Refining and Marketing Company

3M Company

and

United States Steel Corporation

January 1986

Project 4036

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

FILED
JAN 28 1986
PUBLIC SERVICE COMMISSION
FOLDER

Before the

Pennsylvania Public Utility Commission

Docket No. R-850178

Direct

Testimony

of

MELVIN P. BLOOM

On behalf of the

Philadelphia Area Industrial Energy Users Group

(Allied Corporation, Fibers Division
Boeing Vertol Company
B.F. Goodrich, Inc.
The Budd Company
Liquid Air Corporation of North America
Lukens Steel Company
Nabisco Brands, Inc.
SDC (A Burroughs Company)
SmithKline Beckman Corporation
Sun Refining and Marketing Company
3M Company)

and

United States Steel Corporation

January 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

Testimony of Melvin P. Bloom

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Melvin P. Bloom, 1801 N. Front Street, Harrisburg, Pennsylvania.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation with the firm of Drazen-Brubaker & Associates, Inc., utility rate and economic consultants.

Q PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A This is set forth in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Philadelphia Area Industrial Energy User Group (PAIEUG) and U.S. Steel Corporation, all of whom are large high-tension (Rate HT) customers of the Philadelphia Electric Company (the "Company" or "PECO").

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A The following is a summary of my recommendations:

(1) A properly developed coincident peak (4CP) cost-of-service study should be used in this proceeding.

(2) PECO's 4CP cost-of-service study, Exhibit WFS-1, should be rejected because (i) it is based on abnormal weather conditions and (ii) it does not properly reflect the coincident peak demand of Rate HT due to the improper inclusion of non-firm Rate HT customers' demand [Exhibit MPB-1 ( ) and MPB-2 ( )].

(3) PAIEUG et al's adjusted 4CP cost-of-service study [Exhibit MPB-3 ( )], should be utilized (i) as a guide for distributing any rate increase, and (ii) in developing proposed tariff rate charges.

(4) The Company's use of a Bary curve analysis in Rates GS, PD and HT rate design should be rejected since it produces meaningless results due to PECO's mismatching of a coincident peak allocation method for class revenue requirements and an NCP allocation methodology for rate design.

(5) Should the Commission decide to have PECO utilize the Bary curve analysis for rate design then, for consistency and correctness, it should require that a properly developed NCP study be used as a guide to determine rate schedule revenue requirements [Exhibit MPB-4 ( )].

Q WHAT IS THE SUBJECT OF YOUR TESTIMONY?

A I am testifying on the following subjects:

(1) Cost of service;

(i) Problems associated with PECO's cost of service, Exhibit WFS-1.

(ii) Adjustments to correct Exhibit WFS-1 for more normal conditions.

(iii) Alternative cost-of-service studies which are compatible with PECO's rate design philosophy.

(2) PECO's load characteristics; and

(3) The load and supply characteristics of the PJM Interconnected system.

Q WHAT EXHIBITS ARE YOUR SPONSORING?

A I am sponsoring the following exhibits:

Exhibit	Description
MPB-1	Rate of Return at Present Rates, 1974-1986.
MPB-2	EDH Values and Their Affects on the Characteristics of Rate Schedules R and GS.
MPB-3	EDH Adjusted 4CP Cost-of-Service Studies.
MPB-4	NCP Cost-of-Service Studies.

In addition I am sponsoring an analysis of PECO's load characteristics and PECO's load characteristics, and the load and supply characteristics of the PJM Inter connection system in Appendix B.

Cost of Service

Q PLEASE DESCRIBE PECO'S COST-OF-SERVICE STUDY.

A Mr. Sundermier, testifying on behalf of PECO, has presented the results of a fully-embedded cost-of-service study for the future test year, the 12 months ending June 30, 1986--Exhibit WFS-1. The method used by PECO to allocate production and transmission facilities is the four summer coincident peak demand method (the average of each rate schedule's contribution to the monthly peak demand of June, July, August and September). Each rate schedule's monthly coincident peak demand contribution is based upon its 1984 summer monthly peak adjusted by the ratio of annual 1986 projected

sales to annual 1984 sales. Load studies, weather adjusted to 1984 conditions, are used to develop the weekly average one-half hour by one-half hour loads for rate Schedules R (residential), RH (residential - heating), and GS (general service - secondary voltage). Actual one-half hour by one-half hour demand data are used to develop the four summer peak day load profiles for all other rate classifications.

Q WHAT COMMENTS DO YOU HAVE REGARDING PECO'S STUDY?

A I believe the study is unreliable because it utilizes data which is based upon abnormal weather conditions. This, in turn, has the effect of producing unrealistic results. Since the study produces unrealistic results, it should not be used (1) as a guide for distributing any rate increase or (2) in developing proposed tariff rate charges. In addition, the study contains an error in the coincident peak demand data for rate Schedule HT due to the inclusion of demand associated with the Supplemental Energy Provision of the Night Service Rider.

Q DO THE PROBLEMS YOU HAVE WITH PECO'S COST-OF-SERVICE STUDY REQUIRE THAT THE STUDY BE DISREGARDED?

A No. After making the appropriate adjustments to the applicable factors, the study can be used as a guide to assess cost-relatedness and modify, where appropriate, the Company's proposal to distribute the rate increase. Mr. Jeffry Pollock, my

colleague, will discuss this in his direct testimony.

Q HOW DO THE RESULTS OF THE CURRENT COST-OF-SERVICE STUDY COMPARE WITH RESULTS FROM PECO'S PRIOR STUDIES?

A Schedule 1 of Exhibit MPB-1 ( ) shows each rate schedule's present rate of return and the corresponding deviation from system average rate of return for PECO's cost-of-service studies developed from 1974 through the present. For Rate Schedules HT (high tension) and PD (primary voltage), for example, the deviation in rate of return has consistently been increasing--moving farther above cost--except in the current case. For Rate R the exact opposite occurs, i.e., the deviation from system average moves farther below cost--except in the current case.

Q PLEASE DESCRIBE HOW THE CURRENT STUDY UTILIZES UNREALISTIC DEMAND DATA FOR PECO'S WEATHER SENSITIVE RATE CLASSES.

A In developing projected 1986 loads, PECO first developed 1984 loads and adjusted these loads by the ratio of 1986 projected annual sales to 1984 sales. 1984 loads for the weather-sensitive rates, Rate Schedules R, RH and GS, are developed by weather-adjusting average week day loads which were obtained from the Company's load research developed during the period 1980 through 1983.

In general, the effective degree hour (EDH)* for each 1984

*EDH is a variable used by PECO to measure the effect of weather.

summer monthly peak day is used to adjust the load research data in order to develop each weather sensitive rate schedule's one-half hour by one-half hour load profile for each of the four monthly peak days in 1984. A review of the 1980 through 1985 EDH summer peak day data, as shown in Schedule 1 of Exhibit MPB-2 ( ), indicates that in 1984 the actual four summer peak day EDH values were abnormally low. For example, the July, August, September, and the four-month average EDH values for 1984 are all lower than corresponding EDH values in any other year.

Schedule 2 of Exhibit MPB-2 ( ) shows 1984 summer peak day EDH as a percent of 1980 through 1983 average and 1985 peak day EDH. This schedule illustrates that the 1984 average of June-September peak day EDH are approximately 30% lower than either the 1980 through 1983 four-month average or the 1985 June-September average EDH.

Q HOW DO SUMMER PEAK DAY EDH AVERAGES COMPARE WITH PECO'S NORMAL HOT PERIOD EDH OF 213?

A The four summer monthly peak day EDH average as a percent of hot period EDH of 213 EDH for the time periods described above are shown in Schedule 3 of Exhibit MPB-2 ( ). As can be seen, the 1984 EDH percentage deviation of 37.6 % (100.0% - 62.4%) is nearly twice as large as the next greatest percentage deviation of 18.8% (100.0% - 81.2%) for any of the other years.

Q HOW CAN THE EFFECT OF ABNORMAL WEATHER CONDITIONS BE REDUCED IN PECO'S COST-OF-SERVICE STUDY?

A The effect of abnormal weather can be reduced by developing a more normal weather-adjusted future test year. This can be accomplished by adjusting weather-sensitive rate class load research data to either (1) the 1980-1983 monthly peak day average EDH, (2) the 1985 monthly peak day EDH, or (3) typical hot period EDH of 213 EDH.

Q IS A WEATHER ADJUSTMENT PROPER?

A Yes, it is. First, the future test year cost-of-service study contains numerous adjustments to revenues, sales, expenses and costs based upon PECO's future test year budget. The load characteristics of the weather-sensitive classes, however, were abnormal in 1984 and have not been properly adjusted. The lack of proper adjustment to reflect normal conditions will produce aberrations to the output of the cost study. Thus, it is appropriate to apply weather adjustments for the Company's future test year to eliminate these known aberration.

Q PLEASE EXPLAIN HOW THE ABNORMAL 1984 SUMMER WEATHER CONDITIONS EFFECT THE COMPANY'S WEATHER-SENSITIVE RATE SCHEDULES' LOAD CHARACTERISTICS.

A Schedule 4 of Exhibit MPB-2 ( ) compares actual and indexed annual load factor and coincidence factor for Rate Schedules R and

GS for the following periods:

(1) 1980
(2) 1981
(3) 1982
(4) 1980 through 1982 average
(5) 1984

The indexed load factors and coincidence factors are obtained by dividing yearly annual load factor or coincidence factor by corresponding 1980-1982 average values. This schedule shows that historical load factors and coincidence factors are quite similar but 1984 values were significantly different. For Rate Schedule R, for example, the 1984 load factor is 25% higher than the historical average and the 1984 coincidence factor is 19% lower.

Q WHAT EFFECT DO YOUR WEATHER ADJUSTMENTS HAVE ON THE 1984 ANNUAL LOAD FACTOR AND COINCIDENCE FACTOR FOR RATE SCHEDULES R AND GS?

A The effect of weather adjusting the abnormal 1984 weather conditions to more normal conditions is quite significant. Schedule 5 of Exhibit MPB-2 ( ) compares actual and indexed 1984 weather adjusted annual load factors and coincidence factors for Rate Schedules R and GS. The index is developed by dividing each weather adjusted load factor or coincidence factor by the actual 1980-1982 average value. Regardless of the type of weather adjustment, it is seen that the effect of properly adjusting the 1984 data is to produce a set of characteristics which are now consistent with historic values. This is yet another example of the need for and the appropriateness of the weather adjustment.

Q ON TR. 1714, MR. SUNDERMIER INDICATED THAT IT WAS NOT NECESSARY TO EXPLICITLY CORRECT 1984 WEATHER CONDITIONS SINCE 1986 PROJECTED (NORMAL WEATHER) KWH WERE USED IN THE COMPANY'S COST-OF-SERVICE STUDY. PLEASE COMMENT.

A Mr. Sundermier is wrong. For the future test year PECO has projected a load factor for Rate R of 42.3%--a value which is nearly equal to the abnormal 1984 value of 43.8%, and is 21% greater than the 1980-1982 average value. For Rate GS, the future test year load factor is projected to be 53.9%--a value which is close to the 1984 value of 56.1% but is 9% greater than the 1980-1982 average value.

Q WHAT OTHER ADJUSTMENT ARE YOU PROPOSING FOR PECO'S COST-OF-SERVICE STUDY?

A I am proposing a reduction of Rate HT's A-1 demand allocation factor by 32,539 kW. This adjustment, which is quite conservative, consists of the following:

(1) PECO included the coincident demand associated with the Supplemental Energy Provision for Rate HT Customer No. 3 for two of the four summer monthly peak days and did not include any revenue for any customer utilizing this provision; and

(2) Rate HT Customer No. 5 began service on the Supplemental Energy Provision in October, 1984. Since we are dealing with a future test year, it is appropriate to adjust this customer's monthly summer peak day demand downward to firm demand levels.

Q WHY DO YOU BELIEVE THIS ADJUSTMENT IS CONSERVATIVE?

A I believe the adjustment is conservative for the following reasons:

(1) For both Rate HT customers, I have used billing demand as a proxy for the customer's actual monthly peak demand contribution. If diversity would be taken into account, the adjustment would have been greater; and

(2) I have not accounted for the Rate HT Curtailment Rider customers' coincident peak demands which are included in Rate HT's A1 demand allocation factor.

Mr. Pollock will discuss the proper treatment of Rate HT Supplemental Energy Provision and Curtailable Rider customers' non-firm demand in his direct testimony.

Q HAVE YOU RERUN PECO'S COST-OF-SERVICE STUDY WITH THE ADJUSTMENTS DESCRIBED ABOVE?

A Yes, I have. The results are shown in Schedules 1 through 3 of Exhibit MPB-3 ( ). The following is a description of the weather adjustments made in each rerun:

Schedule	EDH Adjustment
1	1980 through 1983 average peak day EDH used.
2	1985 peak day EDH used.
3	213 EDH for each peak day used.

In addition, the A-1 demand allocation factor for Rate HT was reduced by 32,539 kW to reflect the Supplemental Energy Provision problems discussed above.

Q PLEASE DESCRIBE THE RESULTS OF YOUR ANALYSIS.

A The results of my analysis are summarized in Schedule 4 of Exhibit MPB-3 ( ). This schedule tabulates rate of return and revenue subsidy for each rate schedule under each weather adjustment scenario at present and proposed rates. As can be seen, the results of each of the EDH adjustments produce similar results.

Q WHAT IS A REVENUE SUBSIDY?

A A revenue subsidy is the amount of revenue which must be (1) added to a rate schedules' revenue requirement if the rate of return of that rate schedule is below the system-wide average rate of return, or (2) subtracted from a rate schedules' revenue requirement if the rate of return of that rate schedule is above the system-wide average rate of return in order to have all rate schedules produce the system-wide average rate of return.

Q HAVE YOU PREPARED ANY ADDITIONAL COST-OF-SERVICE STUDIES?

A Yes. I have developed a set of non-coincident peak (NCP) cost-of-service studies. The results of these studies are summarized in Schedules 1 through 4 of Exhibit MPB-4 ( ).

Q WHAT IS AN NCP COST-OF-SERVICE STUDY?

A An NCP cost-of-service study is a cost study which allocates production and transmission facilities on the basis of each rate class's maximum noncoincident peak demand.

Q WHY HAVE YOU DEVELOPED THESE NCP STUDIES?

A PECO uses a "Bary curve analysis" to develop the demand and energy charges in its commercial/industrial rates. The application of the Bary curve is described in detail in "Operational Economics of Electric Utilities" by C. W. Bary, Columbia University Press (1965). In his text, Mr. Bary develops a General Unified Theory regarding the design of electric rates which reflect load diversity. On Page 58 of his text, Mr. Bary, in discussing the distribution of load diversity benefits, states:

> The one (allocation method) which is farthest from meeting the requirements of the General Unified Theory is the so-called System Peak Responsibility, which reflects the demand-cost assignment to individual components on the basis of their loads at the time of the system peak load. This method reflects little conceptual perception of the nature and the mutual benefits of load diversity. . . .
>
> * * *
>
> . . . (O)nly the well known Noncoincident Peak (NCP) method, as will be shown in this chapter, conforms to that theory in the practical aspects of its application to the operation of modern electric utilities, because it is but a simplification of the method developed to conform to the concepts of the General Unified Theory . . . .

From the above it is clear that if PECO desires to utilize the Bary curve analysis for commercial/industrial rate design, it must also use an NCP cost-of-service study in order to adhere to Mr. Bary's General Unified Theory. To pick and choose as PECO has done produces meaningless results.

Q DURING CROSS-EXAMINATION, DIDN'T MR. SUNDERMIER INDICATE THAT

PECO'S 4CP METHOD WAS CONSISTENT WITH MR. BARY'S APPROACH SINCE AFTER ALLOCATING COSTS (USING THE 4CP METHOD), THE DEMAND-RELATED REVENUE REQUIREMENT ($/kW) WAS DEVELOPED BY DIVIDING THE 4CP DEMAND REVENUE REQUIREMENT BY THE RATE CLASS'S NONCOINCIDENT DEMAND?

A Yes, but he is wrong. The only way he can be correct is when the demand revenue requirements using the 4CP and the NCP cost studies are identical, which is not the case here.

Q EARLIER YOU INDICATED THAT A MISMATCH OF THE 4CP DEMAND ALLOCATION STUDY WITH THE BARY CURVE ANALYSIS PRODUCES MEANINGLESS RESULTS. PLEASE EXPLAIN.

A On Pages 47 through 54 of Section VII of WFS-1, PECO presented a set of cost-revenue curves for Rate Schedule HT and PD. Each of these curves, drawn for a different assumed monthly maximum demand level, indicates that the revenue curve at proposed rates is <u>always</u> above the cost curve which is developed at the system average rate of return at proposed rate levels. This relationship exists regardless of the level of maximum demand or hours of use. In other words, PECO's curves imply that the return from Rates PD and HT are always above system average--a direct contradiction to the results shown in PECO's cost-of-service study--which was used to develop the unit costs which were then used to generate the cost curves!

Q IN PECO'S 1977 RATE CASE AT DOCKET RID 438, THE COMMISSION ORDERED

THE COMPANY TO RESTRUCTURE RATES PD AND HT SO AS TO ELIMINATE, TO THE EXTENT REASONABLY POSSIBLE, VARIATIONS IN RATES OF RETURN FROM CUSTOMERS WITHIN THOSE CLASSES. DO THE COST VS. REVENUE CURVES SHOWN IN SECTION VII OF EXHIBIT WFS-1 COMPLY WITH THE COMMISSION"S DIRECTIVE?

A These curves appear to comply with the Commission's directive regarding variation in customers' rate of return because the cost and revenue curves are parallel. However, the location of the revenue curve relative to the cost curve is internally inconsistent with the results of the cost-of-service study. All these curves show is that a problem (i.e., an inverse relationship between cost and revenue) exists due to PECO's mixing of allocation methodologies, i.e., the use of a 4CP method for determining a rate schedule's revenue requirements and an NCP (Bary curve) method for collecting the demand-related portion of these costs.

Q DIDN'T MR. SUNDERMIER EXPLAIN AWAY THE PROBLEM, I.E., THE INVERSE RELATIONSHIP BETWEEN REVENUE AND COST YOU DESCRIBED ABOVE?

A Mr. Sundermier's explanation beginning on Tr. 1591 is misleading. Each of the curves shown in Section VII stands alone. For example, the 100 kW Rate HT curve (Page 47 of Exhibit WFS-1) represents the average cost and revenue for a Rate HT 100 kW maximum monthly demand customer at various hours of use. If maximum demand varies by month, then new cost and revenue curves, based upon any month's maximum demand could be constructed and evaluated. It

is obvious, however, from the range of demands used in developing the various Rate HT and PD curves, that the mismatch between revenue and costs exist over all levels of monthly maximum demand. I believe the inverse relationship exists because of an improper matching of the 4CP cost allocation study and the application of an NCP Bary curve analysis for rate design.

Q PLEASE EXPLAIN THE DIFFERENCES BETWEEN SCHEDULES 1 THROUGH 4 OF EXHIBIT MPB-4 ( )?

A The difference between the schedules is due to EDH adjustment as follows:

Schedule	EDH Adjustment Made
1	Monthly peak day EDH as per PECO (1984).
2	Monthly peak day EDH based upon 1980 through 1983 average.
3	Monthly peak day EDH based upon 1985 EDH.
4	Monthly peak day EDH = 213.

Q PLEASE DESCRIBE THE RESULTS OF YOUR NCP STUDIES?

A Each of my studies show that the rate of return for Rate HT and PD is above the system average rate of return. The actual rate of return, and revenue subsidy levels at present and proposed rates is summarized in Schedule 5 of Exhibit MPB-4 ( ).

Q DO THESE STUDIES AFFECT THE COST VS. REVENUE RELATIONSHIP FOR RATE SCHEDULES HT AND PD?

A Yes, they do. They would tend to align the cost vs. revenue

relationships shown in Section VII of Exhibit WFS-1 since the NCP earned rate of return at proposed rates is above the system average rate of return. This illustrates that a consistent application of Mr. Bary's General Unified Theory produces explainable cost vs. revenue relationships. Because of PECO's pick and choose mixing of allocation methodologies and the resulting inverse relationship between cost and revenue, the Bary curve should not be used with the 4CP cost-of-service study.

Q WHEN WOULD IT BE PROPER TO USE THE BARY CURVE ANALYSIS?

A It would only be proper to use the Bary curve analysis if the underlying cost of service study which develops rate class revenue requirements is an NCP study. Thus, if the Commission desires to have PECO utilize the Bary curve in the design of commercial/industrial rates, for consistent application, it must require PECO to use an NCP cost-of-service study such as I have developed in Exhibit MPB-4 ( ). The use of any of these NCP studies would require a redistribution of the requested increase in order to reduce the amount of revenue subsidy increase--supplied or received--by the major rate classes.

LOAD CHARACTERISTICS OF PECO AND THE LOAD AND SUPPLY CHARACTERISTICS OF THE PJM INTERCONNECTION SYSTEM

Q HAVE YOU ANALYZED THE LOAD CHARACTERISTICS OF PECO AND BOTH THE LOAD SUPPLY CHARACTERISTICS OF THE PJM INTERCONNECTION SYSTEM?

A Yes, I have. This analysis appears in Appendix B to my testimony.

Q WHAT DOES THIS ANALYSIS SHOW?

A PECO's firm monthly peak demands for the years 1980 through 1984 are shown in Charts 1 through 5. An analysis of the monthly system peaks as a percent of the annual system peak is presented in Appendix B, Schedule 1 and in Charts 6 through 10. Referring to Schedule 1 for the year 1984, Line 6, of Column 6 shows an index value of 100, which means that the annual firm system peak demand for the year 1984 occurred during the month of June. This means that the firm peak demand experienced in April, 1984 was only 67% of the annual firm system peak demand. Lines 13 and 14 of Schedule 1 show the ratio of the annual system peak demand to the minimum monthly peak and the average monthly peak. If the load pattern were essentially flat (i.e., nonseasonal), then these ratios would be close to 1.0. For PECO, however, the ratio of the maximum-to-minimum monthly peak ranges from 1.38 to 1.55. The ratio of the maximum-to-average monthly peak ranges from 1.19 to 1.28. These ranges indicate that PECO's demands are seasonal and that the maximum demands occur during the summer months. This is also when the annual system peak occurs.

Charts 11 through 15 are an analysis of the monthly system peaks as a percent of the annual system cost on the PJM interconnection system. This analysis demonstrates that the PJM total system load pattern is also highly seasonal and that the annual

system peak always occurs during the summer period. The peak demands during the nonsummer months are generally below 85% of the annual system peak. Thus, the PECO and PJM system monthly load patterns are very similar.

Schedules 2 and 3 of Appendix B, along with Charts 16 through 27, present an analysis of PJM interconnected system's capacity, demand, maintenance outages, reserve and capacity margins, and percentage reserve and capacity margins for the years 1979 through 1984.

Appendix B, Schedule 2, Line 1 (and the curve at the top of Charts 16 through 21), shows the PJM system's net plant capability during each month of the year. The net plant capability represents the amount of installed capacity.

Schedule 2, Line 2 (the bottom curve on the charts) shows the monthly peak demand. Line 3, the reserve margin, is the difference between the net plant capability and the system demand. (This is represented by the shaded area between the two curves on Charts 16 through 21.) The reserve margin indicates the extent to which the PJM system's installed plant capability exceeded the system peak demand. During the month of June, 1984, for example, the margin between plant capability and the system peak demand was 10,580 megawatts, which was 30.0% of the system peak demand. This reserve margin provides a safety cushion against scheduled and unscheduled outages of equipment or other contingencies. An examination of the monthly reserve margins, as shown on Schedule 2,

reveals that the amount of unused capacity is less during the peak summer months than during the nonsummer months.

Recognizing that generating units must be removed from service periodically for maintenance, Schedule 3 and Charts 22 through 27 present an analysis of the PJM system's capacity and demand, with an adjustment for scheduled maintenance. The scheduled maintenance outages are shown on Line 2. These effectively reduce the net plant capability of the PJM system. The adjusted capability is shown on Line 3. (On these charts, the adjusted capability is represented by the middle curve.) The difference between this adjusted capability and the system demand is the capacity margin, which is shown on Schedule 3, Line 5 (and the cross-hatched area between the middle and bottom curves on Charts 21 through 25). The capacity margin, as a percent of the system demand, is shown on Line 6.

The capacity margin is a measure of the generating capacity which is available to offset unforeseen contingencies--such as unexpected increases in demand or forced outages. Unlike scheduled maintenance, which the utility can plan in advance, unexpected increases in demand and forced outages are random events over which the utility has limited control.

Generally, the capacity margins, as a percent of the monthly system peak demand, are lowest during the summer period. This is despite the fact that most scheduled maintenance outages occur during the nonsummer months (in order to maximize the amount of

available capacity during the more critical summer months). This indicates that scheduled maintenance causes no apparent capacity problem and that (since sufficient capacity must be installed to meet the summer system peak demands--with an allowance for reserves) additional demand can be served from existing capacity during the nonsummer period.

Q WHAT ARE YOUR CONCLUSIONS REGARDING THIS ANALYSIS?

A This analysis clearly demonstrates that the supply of electric power is more limited during the summer months. Thus, the critical period on the PECO system occurs during the summer months (both with respect to the magnitude of the summer peak demands and the generally lower reserve and capacity margins). The demands during the nonsummer months are not as critical in terms of the amount of capacity to be installed. Because of the predominant summer-peaking characteristic of the PECO and PJM systems and the generally higher reserve and capacity margins on the PJM system during the nonsummer months, it would be appropriate to allocate production and transmission demand-related costs relative to the demands of each customer class imposed during the summer (peak) period.

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes, it does.

Qualifications of Melvin P. Bloom

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Melvin Bloom, 1801 N. Front Street, Harrisburg, Pennsylvania.

Q BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A I am a consultant in the field of public utility regulation and am employed by Drazen-Brubaker & Associates, Inc., utility rate and economic consultants.

Q WILL YOU STATE BRIEFLY YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE?

A I am a graduate of the Pennsylvania State University, with the degrees of Bachelor of Science in Electric Engineering, Master of Science in Electrical Engineering, and Doctor of Philosophy in Electrical Engineering--with a minor in Applied Mathematics. From 1963 through 1969 I taught courses in Physics, Electric Engineering at the Pennsylvania State University. From 1970 through 1975, I was Supervisor of the Engineering Section of the Environmental Test Laboratory of AMP, Inc. From 1975 through 1980, while employed as an Engineer in the Bureau of Rates of the Pennsylvania Public Utility Commission, I actively participated and testified in nearly all major electric rate cases regarding the subject of cost of service and rate design. In addition, I authored both the preliminary and final Pennsylvania Generic Electric Rate Structure Investigation Report in Docket No. 76-PRMD-7. From 1970 through 1979, I taught

courses in Mathematics and Electrical Engineering for the Pennsylvania State University and the Lebanon Valley College. In May of 1980, I joined the firm of Drazen-Brubaker & Associates, Inc. My work consists of preparation of financial and economic studies relating to electrical and gas utilities, including determination of cost of service and rate design. I have also testified before the Arizona Corporation Commission, Massachusetts Department of Public Utilities, New Jersey Board of Public Utilities, and the New Mexico Public Service Commission.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and has assumed the utility rate and economic consulting activities of Drazen Associates, In., that was active in that field since 1937. In the last five years our firm has participated in more than 700 rate cases in forty states.

The firm provides consulting services in the field of public utility regulation to many clients, including large industrial customers, schools, hospitals, some utilities and, on occasion, state regulatory agencies. For regulatory proceedings, we regularly prepare studies relating the revenue requirements and rate design. We also prepare depreciation and feasibility studies relating to utility service. In making these studies, it is necessary to analyze utilities' operating and financial records, including property records, depreciation studies, revenues, expenses and taxes, cost studies, load studies, forecasts and siting studies. We also assist in the negotiation of contracts for utility service for large users.

In general, we are engaged in regulatory consulting, rate work, feasibility, economic and cost-of-service studies, design of rates for utility services and contract negotiations.

Before the

Pennsylvania Public Utility Commission

Docket No. [illegible]

PHILADELPHIA ELECTRIC COMPANY

Exhibits

of

[illegible]

On Behalf of the

Philadelphia Area Industrial Energy User Group

(Allied Corporation, Fibers Division
Beneficial Corporation
Budd Company, Inc.
The Budd Company
Liquid Air Corporation of North America
Lukens Steel Company
Nabisco Brands, Inc.
SCM (a Pittsburgh Company)
SmithKline Beckman Corporation
Sun Refining and Marketing Company
3M Company)

and

United States Steel Corporation

January 1986

Project 4035

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

PHILADELPHIA ELECTRIC COMPANY

Results of Cost-of-Service Studies at the Then Present Rates
Four Coincident Peak Method
1974 through 1986

Line	Rate Class	1974 (1)	1975 (2)	1976 (3)	1978 (4)	1979 (5)	1981[a] (6)	1982[b] (7)	1983[c] (8)	1984 (9)	1986[d] (10)
	Rate of Return										
1	High Tension	5.51%	7.92%	7.84%	9.41%	9.86%	7.48%	9.69%	11.08%	11.65%	5.51%[e]
2	Primary	7.50	10.20	9.66	10.08	10.64	8.62	11.12	13.29	14.39	6.21
3	Secondary	10.49	11.40	11.21	13.21	12.72	11.32	13.00	15.36	15.57	8.07
4	Residential	5.12	6.40	6.22	7.30	6.15	7.09	4.78	6.28	5.87	6.39
5	Street Lighting	4.85	6.16	6.25	6.52	5.18	5.15	5.37	7.08	8.72	12.58
6	Total Company	6.00%	7.84%	7.77%	9.04%	8.64%	6.23%	8.17%	9.62%	9.70%	6.39%
	Deviation										
7	High Tension	- 0.49	+ 0.08	+ 0.07	+ 0.37	+ 1.22	+ 1.25	+ 1.52	+ 1.46	+ 1.95	- 0.88[e]
8	Primary	+ 1.50	+ 2.36	+ 1.89	+ 1.04	+ 2.00	+ 2.39	+ 2.95	+ 3.67	+ 4.69	- 0.18
9	Secondary	+ 4.49	+ 3.56	+ 3.44	+ 4.17	+ 4.08	+ 5.09	+ 4.92	+ 5.74	+ 5.87	+ 1.68
10	Residential	- 0.88	- 1.44	- 1.55	- 1.74	- 2.49	- 3.14	- 3.39	- 3.34	- 3.83	0.00
11	Street Lighting	- 1.15	- 1.68	- 1.52	- 2.52	- 3.46	- 1.08	- 2.80	- 2.54	- 0.98	+ 6.19

(a) Year Ended March 31, 1981
(b) Year Ended March 31, 1982
(c) Year Ended October 31, 1983
(d) Year Ending June 30, 1986
(e) Includes AMTRAK and SEPTA

PHILADELPHIA ELECTRIC COMPANY

Summer Peak Day EDH
1980 - 1985

Line	Year	June (1)	July (2)	August (3)	September (4)	Average (5)
1	1980	162	273	260	255	238
2	1981	218	263	198	116	199
3	1982	132	231	179	149	173
4	1983	118	206	199	216	185
5	Average (1980-83)	158	243	209	184	199
6	1984	143	170	131	86	133
7	1985	121	212	234	182	187

PHILADELPHIA ELECTRIC COMPANY

1984 Summer Peak Day EDH
as a Percent of 1980-83 EDH and 1985 EDH

Line	Year	June (1)	July (2)	August (3)	September (4)	Average (5)
1	1984	90.5%	70.0%	62.7%	46.7%	66.8%
2	1980-1983 Average	100.0%	100.0%	100.0%	100.0%	100.0%
3	1984	118.2%	80.2%	56.0%	47.3%	71.1%
4	1985	100.0%	100.0%	100.0%	100.0%	100.0%

PHILADELPHIA ELECTRIC COMPANY

Four Summer Peak Day EDH Average
as a Percent of Hot Period EDH
(1980 - 1985)

Line	Year	EDH as a Percent of Hot Period EDH
1	1980	111.7%
2	1981	93.4
3	1982	81.2
4	1983	86.9
5	Average 1980-1983	93.4
6	1984	62.4
7	1985	87.8
8	Hot Period*	100.0%

*Hot Period EDH = 213

PHILADELPHIA ELECTRIC COMPANY

Analysis of Annual Load Factor
and Coincidence Factor
Rates R and GS

Line	Year	Rate R				Rate GS			
		Annual Load Factor (1)	Index[1] (2)	Coincidence Factor (3)	Index[1] (4)	Annual Load Factor (5)	Index[1] (6)	Coincidence Factor (7)	Index[1] (8)
1	1980	32.6%	93	36.0%	101	47.2%	95	51.2%	103
2	1981	36.6	105	33.4	94	48.9	99	49.9	101
3	1982	35.8	102	37.8	106	52.6	106	47.5	96
4	1980-1982 Average	35.0	100	35.7	100	49.6	100	49.5	100
5	1984	43.8%	125	29.0%	81	56.1%	113	46.2%	93

1 - Annual load factor or coincidence factor divided by 1980-1982 average value.

Exhibit MPB-2 ( )
Schedule 4

PHILADELPHIA ELECTRIC COMPANY

Effect of EDH Adjustment on 1984
Load Factor and Coincidence Factor
Rates R and GS

Line	EDH Adjustment	Rate R				Rate GS			
		Annual Load Factor[1] (1)	Index[2] (2)	Coincidence Factor[1] (3)	Index[2] (4)	Annual Load Factor[1] (5)	Index[2] (6)	Coincidence Factor[1] (7)	Index[2] (8)
1	1980-1983 EDH Average	36.9%	105	34.4%	96	49.2%	99	52.7%	106
2	1985 EDH	33.7	96	33.9	95	49.4	100	52.5	106
3	EDH = 213	33.5	96	34.1	96	48.4	98	53.5	108
4	1980-1982 Average	35.0%	100	35.7%	100	49.6%	100	49.5%	100

1 - 1984 data adjusted for EDH.

2 - Annual load factor or coincidence factor divided by 1980-1982 actual average value (Line 4).

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
AVERAGE 1980-1983 EDH STUDY
FOUR PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

RATE BASE	TOTAL	HIGH TENSION	PRIMARY	SECONDARY	RATE RH	RATE R	RATE OP
ELECTRIC PLANT IN SERVICE	$8,893,834	$2,823,930	$ 661,987	$1,235,547	$ 483,647	$3,251,680	$ 22,508
ACCUMULATED PROVISION FOR DEPREC	1,665,850	468,615	117,472	221,797	98,458	660,950	8,361
NET PLANT IN SERVICE	7,227,984	2,355,315	544,515	1,013,750	385,189	2,590,730	14,147
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	272,153	99,969	20,141	34,766	15,584	86,076	3,280
DEDUCTIONS							
ACCELERATED AMORTIZATION	2,323	853	187	333	115	747	0
LIBERALIZED DEPRECIATION	526,166	167,714	39,318	73,194	28,572	191,434	1,316
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	6,963,532	2,286,010	524,767	974,027	371,454	2,480,015	15,993
REVENUE							
SALES	2,251,817	785,557	178,729	328,244	121,780	699,286	23,392
OTHER	38,962	9,962	2,302	4,457	2,052	15,918	950
TOTAL REVENUE	2,290,779	795,519	181,031	332,701	123,832	715,204	24,342
EXPENSES							
OPERATION AND MAINT EXP	1,440,907	515,573	104,794	185,034	82,605	474,479	16,769
DEPRECIATION AND AMORT	264,877	86,897	20,129	36,523	14,057	93,823	871
TAXES OTH THN INCOME TAX	82,178	26,810	6,200	11,654	4,530	28,955	701
INCOME TAXES	34,032	30,555	8,975	16,196	703	-35,085	4,378
PROV FOR DEFERRED INC TAX	41,011	-6,307	2,335	8,433	1,396	33,285	-1,924
INC TX DEF IN PRIOR YR	-13,606	-4,949	-1,090	-1,948	-677	-4,415	-2
INVESTMENT TAX CREDIT	-3,401	-1,084	-254	-473	-185	-1,237	-9
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	1,845,998	647,495	141,089	255,420	102,430	589,805	20,785
NET OPERATING INCOME	444,781	148,024	39,941	77,281	21,403	125,399	3,557
RATE OF RETURN	6.39%	6.48%	7.61%	7.93%	5.76%	5.06%	22.24%
INDEX OF RETURN	100	101	119	124	90	79	348
DEVIATION	.00	.09	1.22	1.55	-.63	-1.33	15.85
REVENUE SUBSIDY	0	4,082	13,048	30,608	-4,719	-67,049	5,150
PROPOSED OPERATING INCOME	$ 884,369	$ 323,891	$ 76,925	$ 141,160	$ 44,437	$ 258,340	$ 5,017
PROPOSED RATE OF RETURN	12.70%	14.17%	14.66%	14.49%	11.96%	10.42%	31.37%
PROPOSED INDEX OF RETURN	100	112	115	114	94	82	247
PROPOSED DEVIATION	.00	1.47	1.96	1.79	-.74	-2.28	18.67
PROPOSED REVENUE SUBSIDY	0	68,189	20,883	35,465	-5,562	-115,022	6,066

Exhibit MPB-3 ( )
Schedule 1
Page 1 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
AVERAGE 1980-1983 EDH STUDY
FOUR PEAK METHOD
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	$ 47,809	$ 66,433	$ 5,395	$ 133,457	$ 14,969	$ 64,437	$ 82,034
ACCUMULATED PROVISION FOR DEPREC	15,586	23,077	1,863	21,524	2,518	11,352	14,278
NET PLANT IN SERVICE	32,223	43,356	3,532	111,933	12,451	53,086	67,756
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	1,224	1,209	188	3,608	472	2,100	3,537
DEDUCTIONS							
ACCELERATED AMORTIZATION	0	0	0	41	4	18	24
LIBERALIZED DEPRECIATION	2,839	3,946	319	7,935	888	3,827	4,862
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	30,355	40,266	3,372	107,564	12,030	51,302	66,377
REVENUE							
SALES	13,431	17,722	2,300	29,633	4,803	18,244	28,696
OTHER	33	20	28	295	33	205	2,708
TOTAL REVENUE	13,464	17,742	2,328	29,928	4,836	18,449	31,404
EXPENSES							
OPERATION AND MAINT EXP	6,592	6,822	1,012	15,090	1,902	10,865	19,369
DEPRECIATION AND AMORT	1,080	2,302	171	4,137	458	1,927	2,500
TAXES OTH THN INCOME TAX	483	635	74	521	59	611	945
INCOME TAXES	1,760	2,050	437	-757	544	1,221	3,055
PROV FOR DEFERRED INC TAX	175	660	-9	3,167	348	-30	-518
INC TX DEF IN PRIOR YR	-6	-7	-1	-240	-26	-106	-141
INVESTMENT TAX CREDIT	-18	-26	-2	-51	-6	-25	-31
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	10,067	12,436	1,683	21,867	3,279	14,464	25,179
NET OPERATING INCOME	3,397	5,306	645	8,061	1,557	3,985	6,225
RATE OF RETURN	11.19%	13.18%	19.12%	7.49%	12.94%	7.77%	9.38%
INDEX OF RETURN	175	206	299	117	203	122	147
DEVIATION	4.80	6.79	12.74	1.11	6.55	1.38	2.99
REVENUE SUBSIDY	2,962	5,554	872	2,418	1,602	1,438	4,033
PROPOSED OPERATING INCOME	$ 3,760	$ 5,531	$ 698	$ 8,062	$ 1,557	$ 6,448	$ 8,543
PROPOSED RATE OF RETURN	12.39%	13.74%	20.70%	7.50%	12.94%	12.57%	12.87%
PROPOSED INDEX OF RETURN	98	108	163	59	102	99	101
PROPOSED DEVIATION	-.31	1.04	6.00	-5.20	.24	-.13	.17
PROPOSED REVENUE SUBSIDY	-194	847	548	-11,372	59	-137	230

Exhibit MPB-3 ( )
Schedule 1
Page 2 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
1985 EDH STUDY
FOUR PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

RATE BASE	TOTAL	HIGH TENSION	PRIMARY	SECONDARY	RATE RH	RATE R	RATE OP
ELECTRIC PLANT IN SERVICE	$8,893,834	$2,871,155	$ 672,201	$1,226,341	$ 475,210	$3,207,112	$ 22,435
ACCUMULATED PROVISION FOR DEPREC	1,665,850	475,777	118,983	220,181	97,058	654,595	8,334
NET PLANT IN SERVICE	7,227,984	2,395,378	553,218	1,006,160	378,151	2,552,517	14,101
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	272,153	100,431	20,252	34,666	15,492	85,594	3,279
DEDUCTIONS							
ACCELERATED AMORTIZATION	2,323	868	190	331	112	732	0
LIBERALIZED DEPRECIATION	526,166	170,534	39,928	72,644	28,068	188,773	1,311
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	6,963,532	2,323,751	532,969	966,894	364,832	2,493,984	15,952
REVENUE							
SALES	2,251,817	785,557	178,729	328,244	121,780	699,286	23,392
OTHER	38,962	10,059	2,323	4,440	2,036	15,823	950
TOTAL REVENUE	2,290,779	795,616	181,052	332,684	123,816	715,109	24,342
EXPENSES							
OPERATION AND MAINT EXP	1,440,907	518,688	105,468	184,426	82,048	471,542	16,764
DEPRECIATION AND AMORT	264,877	88,379	20,451	36,242	13,796	92,410	870
TAXES OTH THN INCOME TAX	82,178	26,993	6,239	11,619	4,497	28,783	701
INCOME TAXES	34,032	26,199	8,030	17,026	1,471	-30,941	4,384
PROV FOR DEFERRED INC TAX	41,011	-5,145	2,567	8,215	1,193	32,172	-1,925
INC TX DEF IN PRIOR YR	-13,606	-5,037	-1,109	-1,932	-662	-4,329	-2
INVESTMENT TAX CREDIT	-3,401	-1,102	-258	-470	-181	-1,220	-8
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	1,845,998	648,975	141,409	255,126	102,162	588,418	20,782
NET OPERATING INCOME	444,781	146,641	39,643	77,558	21,653	126,691	3,559
RATE OF RETURN	6.39%	6.31%	7.44%	8.02%	5.94%	5.18%	22.31%
INDEX OF RETURN	100	99	116	126	93	81	349
DEVIATION	.00	-.08	1.05	1.63	-.45	-1.20	15.93
REVENUE SUBSIDY	0	-3,624	11,378	32,095	-3,351	-59,750	5,161
PROPOSED OPERATING INCOME	$ 884,369	$ 322,508	$ 76,628	$ 141,436	$ 44,687	$ 259,631	$ 5,020
PROPOSED RATE OF RETURN	12.70%	13.88%	14.38%	14.63%	12.25%	10.62%	31.47%
PROPOSED INDEX OF RETURN	100	109	113	115	96	84	248
PROPOSED DEVIATION	.00	1.18	1.68	1.93	-.45	-2.08	18.77
PROPOSED REVENUE SUBSIDY	0	55,643	18,162	37,866	-3,344	-103,102	6,082

Exhibit MPB-3 ( )
Schedule 2
Page 1 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
1985 EDH STUDY
FOUR PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

RATE BASE	RATE SLP	RATE SLS	OTH SL	OTHER UTILITIES	INTER DEPARTMT	SEPTA	AMTRAK
ELECTRIC PLANT IN SERVICE	$ 47,797	$ 66,424	$ 5,392	$ 135,753	$ 15,216	$ 65,436	$ 83,364
ACCUMULATED PROVISION FOR DEPREC	15,580	23,073	1,862	21,873	2,555	11,502	14,477
NET PLANT IN SERVICE	32,217	43,350	3,530	113,880	12,661	53,934	68,887
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	1,223	1,208	168	3,633	474	2,111	3,551
DEDUCTIONS							
ACCELERATED AMORTIZATION	0	0	0	42	5	18	25
LIBERALIZED DEPRECIATION	2,839	3,945	319	8,072	903	3,886	4,942
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	30,349	40,261	3,370	109,398	12,228	52,102	67,443
REVENUE							
SALES	13,431	17,722	2,300	29,633	4,803	18,244	28,696
OTHER	33	20	28	300	33	207	2,711
TOTAL REVENUE	13,464	17,742	2,328	29,933	4,836	18,451	31,407
EXPENSES							
OPERATION AND MAINT EXP	6,591	6,821	1,012	15,242	1,918	10,931	19,455
DEPRECIATION AND AMORT	1,080	2,302	171	4,209	466	1,958	2,542
TAXES OTH THN INCOME TAX	483	635	74	530	60	614	950
INCOME TAXES	1,761	2,051	437	-969	521	1,129	2,933
PROV FOR DEFERRED INC TAX	175	660	-9	3,223	354	-5	-485
INC TX DEF IN PRIOR YR	-6	-7	-1	-244	-26	-107	-143
INVESTMENT TAX CREDIT	-18	-26	-2	-52	-6	-25	-32
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	10,066	12,436	1,683	21,939	3,287	14,495	25,220
NET OPERATING INCOME	3,398	5,306	645	7,994	1,550	3,956	6,187
RATE OF RETURN	11.20%	13.18%	19.14%	7.31%	12.67%	7.59%	9.17%
INDEX OF RETURN	175	206	300	114	198	119	144
DEVIATION	4.81	6.79	12.75	.92	6.29	1.21	2.79
REVENUE SUBSIDY	2,964	5,555	873	2,044	1,561	1,275	3,818
PROPOSED OPERATING INCOME	$ 3,760	$ 5,531	$ 698	$ 7,995	$ 1,550	$ 6,419	$ 8,505
PROPOSED RATE OF RETURN	12.39%	13.74%	20.72%	7.31%	12.67%	12.32%	12.61%
PROPOSED INDEX OF RETURN	96	108	163	58	100	97	99
PROPOSED DEVIATION	-.31	1.04	8.02	-5.39	-.03	-.38	-.09
PROPOSED REVENUE SUBSIDY	-192	849	549	-11,982	-7	-403	-122

Exhibit MPB-3 ( )
Schedule 2
Page 2 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
213 EDH STUDY
FOUR PEAK METHOD
THELVE 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	$2,778,251	$ 651,762	$1,245,027	$ 496,216	$3,291,099	$ 21,739
ACCUMULATED PROVISION FOR DEPREC	1,665,850	461,398	115,799	223,343	100,243	667,578	8,065
NET PLANT IN SERVICE	7,227,984	2,316,854	535,963	1,021,684	395,973	2,623,521	13,675
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	272,153	99,473	20,030	34,869	15,720	86,504	3,271
DEDUCTIONS							
ACCELERATED AMORTIZATION	2,323	839	184	336	119	759	0
LIBERALIZED DEPRECIATION	526,166	164,986	38,708	73,760	29,323	193,788	1,270
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	6,963,532	2,249,798	516,719	981,493	381,622	2,510,856	15,563
REVENUE							
SALES	2,251,817	785,557	178,729	328,244	121,780	699,286	23,392
OTHER	38,962	9,870	2,282	4,476	2,079	15,994	950
TOTAL REVENUE	2,290,779	795,427	181,011	332,720	123,859	715,280	24,342
EXPENSES							
OPERATION AND MAINT EXP	1,440,907	512,558	104,119	185,659	83,434	477,081	16,718
DEPRECIATION AND AMORT	264,877	85,471	19,812	36,818	14,456	95,040	853
TAXES OTH THN INCOME TAX	82,178	26,634	6,160	11,691	4,578	29,107	698
INCOME TAXES	34,032	34,746	9,909	15,330	-467	-38,668	4,434
PROV FOR DEFERRED INC TAX	41,011	-7,420	2,088	8,662	1,711	34,230	-1,936
INC TX DEF IN PRIOR YR	-13,606	-4,866	-1,071	-1,965	-701	-4,483	-2
INVESTMENT TAX CREDIT	-3,401	-1,066	-250	-477	-190	-1,253	-8
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	1,845,998	646,057	140,766	255,719	102,821	591,054	20,757
NET OPERATING INCOME	444,781	149,370	40,245	77,001	21,039	124,225	3,585
RATE OF RETURN	6.39%	6.64%	7.79%	7.85%	5.51%	4.95%	23.04%
INDEX OF RETURN	100	104	122	123	86	77	361
DEVIATION	.00	.25	1.40	1.46	-.87	-1.44	16.65
REVENUE SUBSIDY	0	11,516	14,708	29,069	-6,778	-73,435	5,263
PROPOSED OPERATING INCOME	$ 884,369	$ 325,238	$ 77,229	$ 140,879	$ 44,073	$ 257,166	$ 5,046
PROPOSED RATE OF RETURN	12.70%	14.46%	14.95%	14.35%	11.55%	10.24%	32.42%
PROPOSED INDEX OF RETURN	100	114	118	113	91	81	255
PROPOSED DEVIATION	.00	1.76	2.25	1.65	-1.15	-2.46	19.72
PROPOSED REVENUE SUBSIDY	0	80,266	23,575	32,968	-8,925	-125,363	6,235

Exhibit MPB-3 ( )
Schedule 3
Page 1 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
213 EDH STUDY
FOUR PEAK METHOD
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	$ 47,777	$ 66,415	$ 5,390	$ 131,248	$ 14,727	$ 63,462	$ 80,721
ACCUMULATED PROVISION FOR DEPREC	15,574	23,071	1,861	21,177	2,479	11,196	14,066
NET PLANT IN SERVICE	32,202	43,344	3,529	110,071	12,247	52,266	66,654
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	1,223	1,208	188	3,584	469	2,090	3,523
DEDUCTIONS							
ACCELERATED AMORTIZATION	0	0	0	41	4	18	24
LIBERALIZED DEPRECIATION	2,836	3,945	319	7,803	874	3,768	4,784
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	30,336	40,255	3,369	105,811	11,839	50,530	65,341
REVENUE							
SALES	13,431	17,722	2,300	29,633	4,803	18,244	28,696
OTHER	33	20	28	291	32	203	2,705
TOTAL REVENUE	13,464	17,742	2,328	29,924	4,835	18,447	31,401
EXPENSES							
OPERATION AND MAINT EXP	6,590	6,820	1,011	14,945	1,886	10,800	19,285
DEPRECIATION AND AMORT	1,080	2,302	171	4,068	451	1,697	2,459
TAXES OTH THN INCOME TAX	483	635	74	513	58	607	940
INCOME TAXES	1,762	2,052	438	-554	566	1,311	3,174
PROV FOR DEFERRED INC TAX	175	660	-9	3,113	342	-53	-550
INC TX DEF IN PRIOR YR	-6	-7	-1	-236	-26	-104	-136
INVESTMENT TAX CREDIT	-16	-25	-2	-50	-6	-24	-31
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	10,066	12,436	1,683	21,798	3,272	14,433	25,139
NET OPERATING INCOME	3,398	5,307	645	8,126	1,564	4,014	6,263
RATE OF RETURN	11.20%	13.18%	19.15%	7.68%	13.21%	7.94%	9.59%
INDEX OF RETURN	175	206	300	120	207	124	150
DEVIATION	4.82	6.80	12.76	1.29	6.82	1.56	3.20
REVENUE SUBSIDY	2,967	5,557	673	2,778	1,641	1,597	4,244
PROPOSED OPERATING INCOME	$ 3,761	$ 5,532	$ 698	$ 8,127	$ 1,564	$ 6,477	$ 8,581
PROPOSED RATE OF RETURN	12.40%	13.74%	20.72%	7.68%	13.21%	12.82%	13.13%
PROPOSED INDEX OF RETURN	98	108	163	60	104	101	103
PROPOSED DEVIATION	-.30	1.04	6.02	-5.02	.51	.12	.43
PROPOSED REVENUE SUBSIDY	-187	851	549	-10,788	123	120	574

Exhibit MPB-3 ( )
Schedule 3
Page 2 of 2

PHILADELPHIA ELECTRIC COMPANY

Rate of Return Summary of
4CP Cost of Service
for Various Weather Adjustments
Twelve Months Ending June 30, 1986

Line	Rate Schedule	Present			Proposed		
		1980-1983 EDH Average (1)	1985 EDH (2)	EDH=213 (3)	1980-1983 EDH Average (4)	1985 EDH (5)	EDH=213 (6)
1	HT	6.48%	6.31%	6.64%	14.17%	13.88%	14.46%
2	PD	7.61	7.44	7.79	14.66	14.38	14.95
3	GS	7.93	8.02	7.85	14.49	14.63	14.35
4	RH	5.76	5.94	5.51	11.96	12.25	11.55
5	R	5.06	5.18	4.95	10.42	10.62	10.24
6	OP	22.24	22.31	23.04	31.37	31.47	32.42
7	SLP	11.19	11.20	11.20	12.39	12.39	12.40
8	SLS	13.18	13.18	13.18	13.74	13.74	13.74
9	Other SL	19.12	19.14	19.15	20.70	20.72	20.72
10	Other Utilities	7.49	7.31	7.68	7.50	7.31	7.68
11	Interdepartmental	12.94	12.67	13.21	12.94	12.67	13.21
12	SEPTA	7.77	7.59	7.94	12.57	12.32	12.82
13	AMTRAK	9.38	9.17	9.59	12.87	12.61	13.13
14	Total Company	6.39%	6.39%	6.39%	12.70%	12.70%	12.70%

Exhibit MPB-3 ( )
Schedule 4
Page 1 of 2

PHILADELPHIA ELECTRIC COMPANY

Revenue Subsidy Summary of
4CP Cost of Service
for Various Weather Adjustments
Twelve Months Ending June 30, 1986

Line	Rate Schedule	Present			Proposed		
		1980-1983 EDH Average (000) (1)	1985 EDH (000) (2)	EDH=213 (000) (3)	1980-1983 EDH Average (000) (4)	1985 EDH (000) (5)	EDH=213 (000) (6)
1	HT	$ 4,082	$(3,624)	$11,516	$ 68,189	$ 55,643	$ 80,266
2	PD	13,048	11,378	14,708	20,883	18,162	23,575
3	GS	30,608	32,095	29,069	35,465	37,866	32,968
4	RH	(4,719)	(3,351)	(6,778)	(5,562)	(3,344)	(8,925)
5	R	(67,049)	(59,750)	(73,435)	(115,022)	(103,102)	(125,363)
6	OP	5,150	5,161	5,263	6,066	6,082	6,235
7	SLP	2,962	2,964	2,967	(194)	(192)	(187)
8	SLS	5,554	5,555	5,557	847	849	851
9	Other SL	872	873	873	548	549	549
10	Other Utilities	2,418	2,044	2,778	(11,372)	(11,982)	(10,788)
11	Interdepartmental	1,602	1,561	1,641	59	(7)	123
12	SEPTA	1,438	1,275	1,597	(137)	(403)	120
13	AMTRAK	4,033	3,818	4,244	230	(122)	574
14	Total Company	$ -0-	$ -0-	$ -0-	$ -0-	$ -0-	$ -0-

Exhibit MPB-3 ( )
Schedule 4
Page 2 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
COMPANY STUDY
NON-COINCIDENT PEAK METHOD
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	$2,772,037	$ 714,737	$1,028,339	$ 819,919	$2,914,476	$ 125,465
ACCUMULATED PROVISION FOR DEPREC	1,665,850	462,244	126,515	189,360	151,724	605,192	24,227
NET PLANT IN SERVICE	7,227,984	2,309,793	588,223	838,979	668,196	2,309,284	101,239
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	272,153	99,411	20,715	32,520	19,234	82,418	4,397
DEDUCTIONS							
ACCELERATED AMORTIZATION	2,323	835	203	268	220	644	33
LIBERALIZED DEPRECIATION	526,166	164,615	42,469	60,820	48,653	171,297	7,464
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	6,963,532	2,243,015	565,865	809,458	637,889	2,215,230	98,021
REVENUE							
SALES	2,251,817	785,557	178,729	328,244	121,780	699,286	23,392
OTHER	38,962	9,844	2,403	4,038	2,725	15,261	1,160
TOTAL REVENUE	2,290,779	795,401	181,132	332,282	124,505	714,547	24,552
EXPENSES							
OPERATION AND MAINT EXP	1,440,907	512,185	108,284	171,375	104,803	452,254	23,562
DEPRECIATION AND AMORT	264,877	85,224	21,756	30,047	24,537	83,383	4,096
TAXES OTH THN INCOME TAX	82,178	26,611	6,404	10,854	5,829	27,652	1,099
INCOME TAXES	34,032	35,440	4,185	35,226	-30,126	-4,371	-5,099
PROV FOR DEFERRED INC TAX	41,011	-7,633	3,597	3,369	9,588	25,159	600
INC TX DEF IN PRIOR YR	-13,606	-4,843	-1,181	-1,569	-1,286	-3,819	-192
INVESTMENT TAX CREDIT	-3,401	-1,064	-275	-393	-314	-1,107	-48
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	1,845,998	645,919	142,770	248,909	113,023	579,149	24,017
NET OPERATING INCOME	444,781	149,481	38,361	83,372	11,482	135,398	534
RATE OF RETURN	6.39%	6.66%	6.78%	10.30%	1.80%	6.11%	.54%
INDEX OF RETURN	100	104	106	161	28	96	9
DEVIATION	.00	.28	.39	3.91	-4.59	-.28	-5.84
REVENUE SUBSIDY	0	12,622	4,506	64,334	-59,442	-12,383	-11,633
PROPOSED OPERATING INCOME	$ 884,369	$ 325,349	$ 75,345	$ 147,251	$ 34,516	$ 268,338	$ 1,995
PROPOSED RATE OF RETURN	12.70%	14.50%	13.32%	18.19%	5.41%	12.11%	2.03%
PROPOSED INDEX OF RETURN	100	114	105	143	43	95	16
PROPOSED DEVIATION	.00	1.80	.62	5.49	-7.29	-.59	-10.67
PROPOSED REVENUE SUBSIDY	0	82,242	7,070	90,295	-94,451	-26,400	-21,236

Exhibit MPB-4 ( )
Schedule 1
Page 1 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
COMPANY STUDY
NON-COINCIDENT PEAK METHOD
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	$ 75,381	$ 84,219	$ 10,162	$ 100,509	$ 14,974	$ 86,448	$ 147,167
ACCUMULATED PROVISION FOR DEPREC	19,892	25,855	2,608	16,506	2,532	14,793	24,403
NET PLANT IN SERVICE	55,488	58,363	7,555	84,002	12,443	71,656	122,764
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	1,523	1,402	239	3,251	472	2,339	4,233
DEDUCTIONS							
ACCELERATED AMORTIZATION	9	6	2	31	4	25	45
LIBERALIZED DEPRECIATION	4,436	5,008	604	5,968	888	5,141	8,752
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	52,262	54,398	7,160	81,255	12,022	68,789	118,169
REVENUE							
SALES	13,431	17,722	2,300	29,633	4,803	18,244	28,696
OTHER	89	56	37	228	33	249	2,840
TOTAL REVENUE	13,520	17,778	2,337	29,861	4,836	18,493	31,536
EXPENSES							
OPERATION AND MAINT EXP	8,412	7,996	1,326	12,918	1,902	12,318	23,572
DEPRECIATION AND AMORT	1,942	2,858	320	3,103	458	2,615	4,538
TAXES OTH THN INCOME TAX	589	704	93	394	59	696	1,195
INCOME TAXES	-773	416	-1	2,280	544	-802	-2,888
PROV FOR DEFERRED INC TAX	849	1,094	108	2,357	348	508	1,076
INC TX DEF IN PRIOR YR	-56	-40	-9	-179	-26	-146	-260
INVESTMENT TAX CREDIT	-29	-32	-4	-39	-6	-33	-57
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	10,934	12,996	1,833	20,835	3,280	15,156	27,176
NET OPERATING INCOME	2,586	4,782	505	9,026	1,556	3,337	4,360
RATE OF RETURN	4.95%	8.79%	7.05%	11.11%	12.94%	4.85%	3.69%
INDEX OF RETURN	77	138	110	174	203	76	58
DEVIATION	-1.44	2.40	.66	4.72	6.56	-1.54	-2.70
REVENUE SUBSIDY	-1,528	2,657	96	7,792	1,601	-2,147	-6,475
PROPOSED OPERATING INCOME	$ 2,948	$ 5,007	$ 558	$ 9,027	$ 1,556	$ 5,800	$ 6,679
PROPOSED RATE OF RETURN	5.64%	9.21%	7.79%	11.11%	12.94%	8.43%	5.65%
PROPOSED INDEX OF RETURN	44	72	61	87	102	66	45
PROPOSED DEVIATION	-7.06	-3.49	-4.91	-1.59	.24	-4.27	-7.05
PROPOSED REVENUE SUBSIDY	-7,494	-3,862	-714	-2,625	60	-5,965	-16,919

Exhibit MPB-4 ( )
Schedule 1
Page 2 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
AVERAGE 1980-1983 EDH STUDY
NON-COINCIDENT PEAK METHOD
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	$2,590,049	$ 668,631	$1,079,319	$ 766,989	$3,168,171	$ 128,619
ACCUMULATED PROVISION FOR DEPREC	1,665,850	432,572	118,496	197,721	142,123	648,080	24,714
NET PLANT IN SERVICE	7,227,984	2,157,477	550,136	881,598	624,867	2,520,091	103,905
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	272,153	97,435	20,214	33,073	18,657	85,174	4,431
DEDUCTIONS							
ACCELERATED AMORTIZATION	2,323	778	189	283	205	720	34
LIBERALIZED DEPRECIATION	526,166	153,747	39,715	63,864	45,493	186,447	7,652
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	6,963,532	2,099,679	530,062	849,561	597,194	2,413,486	100,532
REVENUE							
SALES	2,251,817	785,557	178,729	328,244	121,780	699,286	23,392
OTHER	38,962	9,484	2,315	4,138	2,630	15,748	1,166
TOTAL REVENUE	2,290,779	795,041	181,044	332,382	124,410	715,034	24,558
EXPENSES							
OPERATION AND MAINT EXP	1,440,907	500,169	105,239	174,738	101,303	469,000	23,770
DEPRECIATION AND AMORT	264,877	79,571	20,337	31,630	22,932	91,207	4,195
TAXES OTH THN INCOME TAX	82,178	25,908	6,226	11,051	5,624	28,633	1,111
INCOME TAXES	34,032	52,071	8,360	30,571	-25,381	-27,413	-5,389
PROV FOR DEFERRED INC TAX	41,011	-12,040	2,498	4,603	8,343	31,237	677
INC TX DEF IN PRIOR YR	-13,606	-4,518	-1,102	-1,660	-1,199	-4,261	-198
INVESTMENT TAX CREDIT	-3,401	-994	-257	-413	-294	-1,205	-49
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	1,845,998	640,166	141,301	250,521	111,328	587,199	24,116
NET OPERATING INCOME	444,781	154,875	39,743	81,862	13,083	127,835	442
RATE OF RETURN	6.39%	7.38%	7.50%	9.64%	2.19%	5.30%	.44%
INDEX OF RETURN	100	115	117	151	34	83	7
DEVIATION	.00	.99	1.11	3.25	-4.20	-1.09	-5.95
REVENUE SUBSIDY	0	42,177	11,958	56,062	-50,910	-53,469	-12,147
PROPOSED OPERATING INCOME	$ 884,369	$ 330,743	$ 76,727	$ 145,740	$ 36,117	$ 260,775	$ 1,902
PROPOSED RATE OF RETURN	12.70%	15.75%	14.48%	17.15%	6.05%	10.80%	1.89%
PROPOSED INDEX OF RETURN	100	124	114	135	48	85	15
PROPOSED DEVIATION	.00	3.05	1.78	4.45	-6.65	-1.90	-10.81
PROPOSED REVENUE SUBSIDY	0	130,178	19,114	76,880	-80,701	-92,911	-22,072

Exhibit MPB-4 ( )
Schedule 2
Page 1 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
AVERAGE 1980-1983 EDH STUDY
NON-COINCIDENT PEAK METHOD
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	$ 73,261	$ 82,863	$ 9,799	$ 93,788	$ 13,984	$ 80,981	$ 137,379
ACCUMULATED PROVISION FOR DEPREC	19,508	25,609	2,542	15,410	2,366	13,901	22,807
NET PLANT IN SERVICE	53,753	57,253	7,257	78,377	11,618	67,080	114,572
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	1,500	1,387	236	3,178	461	2,280	4,128
DEDUCTIONS							
ACCELERATED AMORTIZATION	8	5	1	29	4	23	42
LIBERALIZED DEPRECIATION	4,359	4,927	582	5,566	829	4,815	8,168
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	50,633	53,355	6,881	75,960	11,246	64,483	110,462
REVENUE							
SALES	13,431	17,722	2,300	29,633	4,803	18,244	28,696
OTHER	85	54	37	214	31	238	2,821
TOTAL REVENUE	13,516	17,776	2,337	29,847	4,834	18,482	31,517
EXPENSES							
OPERATION AND MAINT EXP	8,272	7,906	1,302	12,474	1,837	11,957	22,940
DEPRECIATION AND AMORT	1,678	2,817	309	2,895	427	2,445	4,234
TAXES OTH THN INCOME TAX	581	699	91	368	55	674	1,157
INCOME TAXES	-583	538	32	2,894	635	-302	-2,000
PROV FOR DEFERRED INC TAX	799	1,063	99	2,194	324	376	839
INC TX DEF IN PRIOR YR	-53	-38	-9	-167	-24	-136	-243
INVESTMENT TAX CREDIT	-28	-32	-4	-36	-5	-31	-53
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	10,866	12,952	1,821	20,622	3,248	14,983	26,874
NET OPERATING INCOME	2,650	4,824	515	9,225	1,586	3,499	4,643
RATE OF RETURN	5.23%	9.04%	7.49%	12.14%	14.10%	5.43%	4.20%
INDEX OF RETURN	62	142	117	190	221	85	66
DEVIATION	-1.15	2.65	1.10	5.76	7.71	-.96	-2.18
REVENUE SUBSIDY	-1,187	2,876	154	8,883	1,762	-1,259	-4,901
PROPOSED OPERATING INCOME	$ 3,012	$ 5,048	$ 569	$ 9,226	$ 1,586	$ 5,962	$ 6,961
PROPOSED RATE OF RETURN	5.95%	9.46%	8.26%	12.15%	14.10%	9.25%	6.30%
PROPOSED INDEX OF RETURN	47	75	65	96	111	73	50
PROPOSED DEVIATION	-6.75	-3.24	-4.44	-.55	1.40	-3.45	-6.40
PROPOSED REVENUE SUBSIDY	-6,943	-3,510	-620	-854	320	-4,525	-14,357

Exhibit MPB-4 ( )
Schedule 2
Page 2 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
1985 EDH STUDY
NON-COINCIDENT PEAK METHOD
THELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

RATE BASE	TOTAL	HIGH TENSION	PRIMARY	SECONDARY	RATE RH	RATE R	RATE OP
ELECTRIC PLANT IN SERVICE	$8,893,634	$2,577,115	$ 665,361	$1,071,022	$ 763,247	$3,198,937	$ 128,001
ACCUMULATED PROVISION FOR DEPREC	1,665,850	430,463	117,929	196,245	141,447	653,335	24,602
NET PLANT IN SERVICE	7,227,984	2,146,652	547,432	874,777	621,800	2,545,602	103,399
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	272,153	97,295	20,178	32,983	18,617	85,508	4,424
DEDUCTIONS							
ACCELERATED AMORTIZATION	2,323	774	168	281	204	729	34
LIBERALIZED DEPRECIATION	526,166	152,975	39,520	63,369	45,269	188,285	7,616
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	6,963,532	2,089,492	527,520	843,152	594,313	2,437,474	100,057
REVENUE							
SALES	2,251,817	785,557	178,729	328,244	121,780	699,286	23,392
OTHER	38,962	9,459	2,309	4,123	2,624	15,806	1,165
TOTAL REVENUE	2,290,779	795,016	181,038	332,367	124,404	715,092	24,557
EXPENSES							
OPERATION AND MAINT EXP	1,440,907	493,315	105,023	174,190	101,056	471,031	23,729
DEPRECIATION AND AMORT	264,877	79,169	20,237	31,377	22,818	92,154	4,176
TAXES OTH THN INCOME TAX	82,178	25,858	6,213	11,019	5,610	28,752	1,109
INCOME TAXES	34,032	53,253	8,657	31,318	-25,045	-30,202	-5,334
PROV FOR DEFERRED INC TAX	41,011	-12,354	2,420	4,407	8,255	31,972	663
INC TX DEF IN PRIOR YR	-13,606	-4,495	-1,096	-1,646	-1,193	-4,314	-197
INVESTMENT TAX CREDIT	-3,401	-989	-255	-410	-293	-1,217	-49
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	1,845,998	639,757	141,197	250,255	111,208	588,176	24,097
NET OPERATING INCOME	444,781	155,259	39,841	82,112	13,196	126,916	460
RATE OF RETURN	6.392	7.432	7.552	9.742	2.222	5.212	.462
INDEX OF RETURN	100	116	118	152	35	82	7
DEVIATION	.00	1.04	1.17	3.35	-4.17	-1.18	-5.93
REVENUE SUBSIDY	0	44,278	12,407	57,401	-50,307	-58,449	-12,047
OPOSED OPERATING INCOME	$ 884,369	$ 331,126	$ 76,825	$ 145,990	$ 36,230	$ 259,856	$ 1,921
OPOSED RATE OF RETURN	12.702	15.852	14.562	17.312	6.102	10.662	1.922
OPOSED INDEX OF RETURN	100	125	115	136	48	84	15
OPOSED DEVIATION	.00	3.15	1.86	4.61	-6.60	-2.04	-10.78
OPOSED REVENUE SUBSIDY	0	133,585	19,969	79,041	-79,728	-100,966	-21,911

Exhibit MPB-4 ( )
Schedule 3
Page 1 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
1985 EDH STUDY
NON-COINCIDENT PEAK METHOD
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	$ 73,111	$ 82,767	$ 9,773	$ 93,310	$ 13,914	$ 80,592	$ 136,684
ACCUMULATED PROVISION FOR DEPREC	19,461	25,592	2,537	15,332	2,355	13,838	22,694
NET PLANT IN SERVICE	53,630	57,175	7,236	77,978	11,560	66,755	113,990
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	1,498	1,386	235	3,172	460	2,276	4,121
DEDUCTIONS							
ACCELERATED AMORTIZATION	8	5	1	29	4	23	42
LIBERALIZED DEPRECIATION	4,350	4,921	581	5,538	825	4,791	8,126
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	50,517	53,282	6,861	75,584	11,191	64,177	109,914
REVENUE							
SALES	13,431	17,722	2,300	29,633	4,803	18,244	28,696
OTHER	85	54	37	213	31	238	2,820
TOTAL REVENUE	13,516	17,776	2,337	29,846	4,834	18,482	31,516
EXPENSES							
OPERATION AND MAINT EXP	8,262	7,900	1,301	12,443	1,832	11,931	22,895
DEPRECIATION AND AMORT	1,873	2,814	308	2,880	425	2,433	4,212
TAXES OTH THN INCOME TAX	581	698	91	366	55	673	1,155
INCOME TAXES	-570	546	34	2,938	641	-266	-1,937
PROV FOR DEFERRED INC TAX	796	1,060	98	2,182	322	367	822
INC TX DEF IN PRIOR YR	-52	-38	-9	-166	-24	-135	-241
INVESTMENT TAX CREDIT	-28	-32	-4	-36	-5	-31	-53
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	10,861	12,949	1,820	20,607	3,246	14,971	26,853
NET OPERATING INCOME	2,654	4,826	516	9,239	1,588	3,511	4,663
RATE OF RETURN	5.25%	9.06%	7.53%	12.22%	14.19%	5.47%	4.24%
INDEX OF RETURN	82	142	118	191	222	86	66
DEVIATION	-1.13	2.67	1.14	5.84	7.80	-.92	-2.14
REVENUE SUBSIDY	-1,162	2,891	159	8,961	1,773	-1,196	-4,789
PROPOSED OPERATING INCOME	$ 3,017	$ 5,051	$ 569	$ 9,240	$ 1,588	$ 5,973	$ 6,981
PROPOSED RATE OF RETURN	5.97%	9.48%	8.30%	12.23%	14.19%	9.31%	6.35%
PROPOSED INDEX OF RETURN	47	75	65	96	112	73	50
PROPOSED DEVIATION	-6.73	-3.22	-4.40	-.47	1.49	-3.39	-6.35
PROPOSED REVENUE SUBSIDY	-6,905	-3,485	-613	-729	338	-4,423	-14,175

Exhibit MPB-4 ( )
Schedule 3
Page 2 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
Z13 EOH STUDY
NON-COINCIDENT PEAK METHOD
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	$2,570,159	$ 663,602	$1,086,420	$ 761,237	$3,203,440	$ 119,849
ACCUMULATED PROVISION FOR DEPREC	1,665,850	429,329	117,624	198,901	141,085	654,069	23,184
NET PLANT IN SERVICE	7,227,984	2,140,830	545,978	887,520	620,152	2,549,371	96,665
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	272,153	97,219	20,159	33,150	18,595	85,557	4,336
DEDUCTIONS							
ACCELERATED AMORTIZATION	2,323	772	188	286	203	731	31
LIBERALIZED DEPRECIATION	526,166	152,560	39,415	64,288	45,149	188,554	7,129
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	6,963,532	2,084,013	526,154	855,132	592,766	2,441,020	93,727
REVENUE							
SALES	2,251,817	785,557	176,729	328,244	121,780	699,286	23,392
OTHER	38,962	9,445	2,306	4,152	2,620	15,815	1,150
TOTAL REVENUE	2,290,779	795,002	181,035	332,396	124,400	715,101	24,542
EXPENSES							
OPERATION AND MAINT EXP	1,440,907	498,856	104,906	175,207	100,923	471,328	23,191
DEPRECIATION AND AMORT	264,877	78,953	20,183	31,850	22,757	92,294	3,926
TAXES OTH THN INCOME TAX	82,178	25,831	6,206	11,079	5,602	28,769	1,077
INCOME TAXES	34,032	53,868	8,816	29,924	-24,864	-30,614	-4,597
PROV FOR DEFERRED INC TAX	41,011	-12,522	2,378	4,774	8,208	32,081	469
INC TX DEF IN PRIOR YR	-13,606	-4,482	-1,093	-1,672	-1,190	-4,322	-183
INVESTMENT TAX CREDIT	-3,401	-986	-255	-416	-292	-1,219	-46
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	1,845,998	639,537	141,141	250,745	111,144	588,318	23,837
NET OPERATING INCOME	444,781	155,465	39,894	81,651	13,257	126,783	705
RATE OF RETURN	6.39%	7.46%	7.58%	9.55%	2.24%	5.19%	.75%
INDEX OF RETURN	100	117	119	149	35	81	12
DEVIATION	.00	1.07	1.19	3.16	-4.15	-1.19	-5.64
REVENUE SUBSIDY	0	45,408	12,771	54,910	-49,983	-59,180	-10,729
PROPOSED OPERATING INCOME	$ 884,369	$ 331,332	$ 76,878	$ 145,529	$ 36,291	$ 259,723	$ 2,165
PROPOSED RATE OF RETURN	12.70%	15.90%	14.61%	17.02%	6.12%	10.64%	2.31%
PROPOSED INDEX OF RETURN	100	125	115	134	48	84	18
PROPOSED DEVIATION	.00	3.20	1.91	4.32	-6.58	-2.06	-10.39
PROPOSED REVENUE SUBSIDY	0	135,418	20,428	75,014	-79,205	-102,152	-19,782

Exhibit MPB-4 ( )
Schedule 4
Page 1 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
213 EDH STUDY
NON-COINCIDENT PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

RATE BASE	RATE SLP	RATE SLS	OTH SL	OTHER UTILITIES	INTER DEPARTMT	SEPTA	AMTRAK
ELECTRIC PLANT IN SERVICE	$ 73,031	$ 82,715	$ 9,760	$ 93,053	$ 13,876	$ 80,383	$ 136,310
ACCUMULATED PROVISION FOR DEPREC	19,466	25,583	2,535	15,290	2,348	13,804	22,633
NET PLANT IN SERVICE	53,564	57,133	7,225	77,763	11,527	66,580	113,676
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	1,497	1,385	235	3,170	460	2,273	4,117
DEDUCTIONS							
ACCELERATED AMORTIZATION	8	5	1	29	4	23	42
LIBERALIZED DEPRECIATION	4,346	4,918	580	5,522	823	4,779	8,104
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	50,455	53,242	6,850	75,301	11,160	64,012	109,619
REVENUE							
SALES	13,431	17,722	2,300	29,633	4,803	18,244	28,696
OTHER	84	54	37	213	31	237	2,819
TOTAL REVENUE	13,515	17,776	2,337	29,846	4,834	18,481	31,515
EXPENSES							
OPERATION AND MAINT EXP	8,256	7,896	1,300	12,426	1,830	11,917	22,871
DEPRECIATION AND AMORT	1,871	2,812	308	2,872	424	2,427	4,201
TAXES OTH THN INCOME TAX	580	696	91	365	55	672	1,153
INCOME TAXES	-562	551	35	2,961	644	-247	-1,903
PROV FOR DEFERRED INC TAX	794	1,059	98	2,176	321	362	813
INC TX DEF IN PRIOR YR	-52	-37	-9	-165	-24	-135	-241
INVESTMENT TAX CREDIT	-28	-32	-4	-36	-5	-31	-52
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	10,859	12,948	1,820	20,599	3,245	14,965	26,841
NET OPERATING INCOME	2,657	4,828	517	9,247	1,589	3,517	4,674
RATE OF RETURN	5.27%	9.07%	7.54%	12.27%	14.24%	5.49%	4.26%
INDEX OF RETURN	82	142	118	192	223	86	67
DEVIATION	-1.12	2.68	1.16	5.88	7.85	-.89	-2.12
REVENUE SUBSIDY	-1,149	2,899	161	9,003	1,780	-1,162	-4,729
PROPOSED OPERATING INCOME	$ 3,019	$ 5,053	$ 570	$ 9,248	$ 1,589	$ 5,980	$ 6,992
PROPOSED RATE OF RETURN	5.98%	9.49%	8.32%	12.27%	14.24%	9.34%	6.38%
PROPOSED INDEX OF RETURN	47	75	66	97	112	74	50
PROPOSED DEVIATION	-6.72	-3.21	-4.38	-.43	1.54	-3.36	-6.32
PROPOSED REVENUE SUBSIDY	-6,884	-3,471	-610	-661	348	-4,367	-14,077

Exhibit MPB-4 ( )
Schedule 4
Page 2 of 2

PHILADELPHIA ELECTRIC COMPANY

Rate of Return Summary of Noncoincident Peak
Cost of Service for Various Weather Adjustments
Twelve Months Ending June 30, 1986

		Present				Proposed			
Line	Rate Schedule	PECO EDH (1)	1980-1983 EDH Average (2)	1985 EDH (3)	EDH=213 (4)	PECO EDH (5)	1980-1983 EDH Average (6)	1985 EDH (7)	EDH=213 (8)
1	HT	6.66%	7.38%	7.43%	7.46%	14.50%	15.75%	15.85%	15.90%
2	PD	6.78	7.50	7.55	7.58	13.32	14.48	14.56	14.61
3	GS	10.30	9.64	9.74	9.55	18.19	17.15	17.31	17.02
4	RH	1.80	2.19	2.22	2.24	5.41	6.05	6.10	6.12
5	R	6.11	5.30	5.21	5.19	12.11	10.80	10.66	10.64
6	OP	0.54	0.44	0.46	0.75	2.03	1.89	1.92	2.31
7	SLP	4.95	5.23	5.25	5.27	5.64	5.95	5.97	5.98
8	SLS	8.79	9.04	9.06	9.07	9.21	9.46	9.48	9.49
9	Other SL	7.05	7.49	7.53	7.54	7.79	8.26	8.30	8.32
10	Other Utilities	11.11	12.14	12.22	12.27	11.11	12.15	12.23	12.27
11	Interdepartmental	12.94	14.10	14.19	14.24	12.94	14.10	14.19	14.24
12	SEPTA	4.85	5.43	5.47	5.49	8.43	9.25	9.31	9.34
13	AMTRAK	3.69	4.20	4.24	4.26	5.65	6.30	6.35	6.38
14	Total Company	6.39%	6.39%	6.39%	6.39%	12.70%	12.70%	12.70%	12.70%

Exhibit MPB-4 ( )
Schedule 5
Page 1 of 2

PHILADELPHIA ELECTRIC COMPANY

Revenue Subsidy Summary of Noncoincident Peak
Cost of Service for Various Weather Adjustments
Twelve Months Ending June 30, 1986

		Present				Proposed			
Line	Rate Schedule	PECO EDH (000) (1)	1980-1983 EDH Average (000) (2)	1985 EDH (000) (3)	EDH=213 (000) (4)	PECO EDH (000) (5)	1980-1983 EDH Average (000) (6)	1985 EDH (000) (7)	EDH=213 (000) (8)
1	HT	$ 12,622	$ 42,177	$ 44,278	$ 45,408	$ 82,242	$ 130,178	$ 133,585	$ 135,418
2	PD	4,506	11,958	12,487	12,771	7,070	19,114	19,969	20,428
3	GS	64,334	56,062	57,401	54,910	90,295	76,880	79,041	75,014
4	RH	(59,442)	(50,910)	(50,307)	(49,983)	(94,451)	(80,701)	(79,728)	(79,205)
5	R	(12,383)	(53,469)	(58,449)	(59,180)	(26,400)	(92,911)	(100,966)	(102,152)
6	OP	(11,633)	(12,147)	(12,047)	(10,729)	(21,236)	(22,072)	(21,911)	(19,782)
7	SLP	(1,528)	(1,187)	(1,162)	(1,149)	(7,494)	(6,943)	(6,905)	(6,884)
8	SLS	2,657	2,876	2,891	2,899	(3,862)	(3,510)	(3,485)	(3,471)
9	Other SL	96	154	159	161	(714)	(620)	(613)	(610)
10	Other Utilities	7,792	8,883	8,961	9,003	(2,625)	(854)	(729)	(661)
11	Interdepartmental	1,601	1,762	1,773	1,780	60	320	338	348
12	SEPTA	(2,147)	(1,259)	(1,196)	(1,162)	(5,965)	(4,525)	(4,423)	(4,367)
13	AMTRAK	(6,475)	(4,901)	(4,789)	(4,729)	(16,919)	(14,357)	(14,175)	(14,077)
14	Total Company	$ -0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0

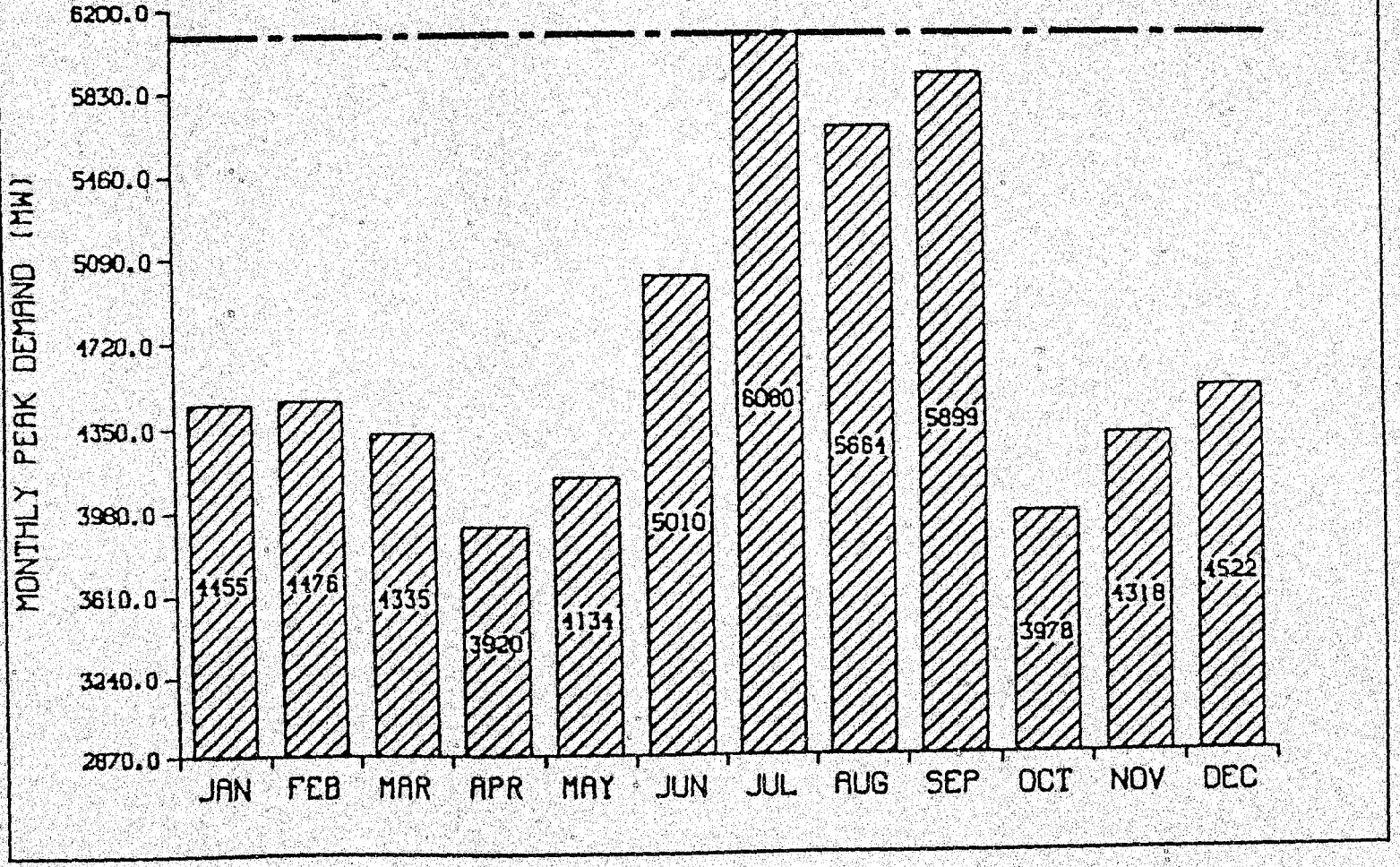
Exhibit MPB-4 ( )
Schedule 5
Page 2 of 2

INDEX TO APPENDIX B
OF THE TESTIMONY OF MELVIN BLOOM

Reference	Description
Charts 1-5	Analysis of PECO Monthly Peak Demands
Schedule 1 and Charts 6-10	PECO Monthly Peak Demands as a Percent of the Annual System Peak
Charts 11-15	Analysis of PJM Monthly Peak Demands as a Percent of Annual System Peak
Schedule 2 and Charts 16-21	Analysis of PJM Monthly Reserve Margins
Schedule 3 and Charts 22-27	Analysis of PJM Monthly Capacity Margins

PHILADELPHIA ELECTRIC COMPANY

ANALYSIS OF MONTHLY PEAK DEMANDS
YEAR ENDED DECEMBER 31, 1980



Appendix B
Chart 1

PHILADELPHIA ELECTRIC COMPANY

ANALYSIS OF MONTHLY PEAK DEMANDS
YEAR ENDED DECEMBER 31, 1981

MONTHLY PEAK DEMAND (MW)

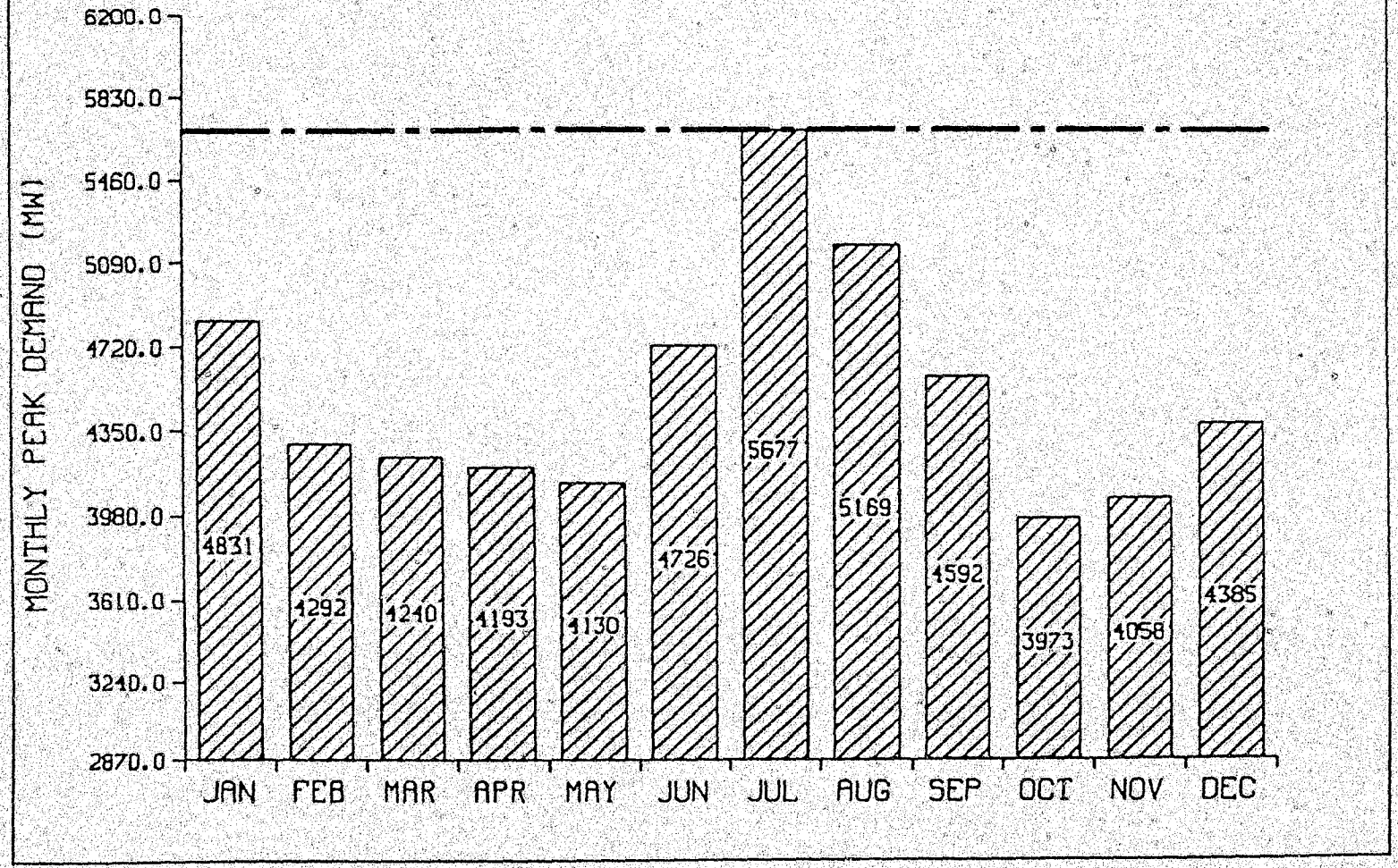
2870.0
3240.0
3610.0
3980.0
4350.0
4720.0
5090.0
5460.0
5830.0
6200.0

JAN	4787
FEB	4582
MAR	4249
APR	3998
MAY	4167
JUN	5474
JUL	5716
AUG	5328
SEP	4638
OCT	3895
NOV	4140
DEC	4390

PHILADELPHIA ELECTRIC COMPANY

ANALYSIS OF MONTHLY PEAK DEMANDS

YEAR ENDED DECEMBER 31, 1982

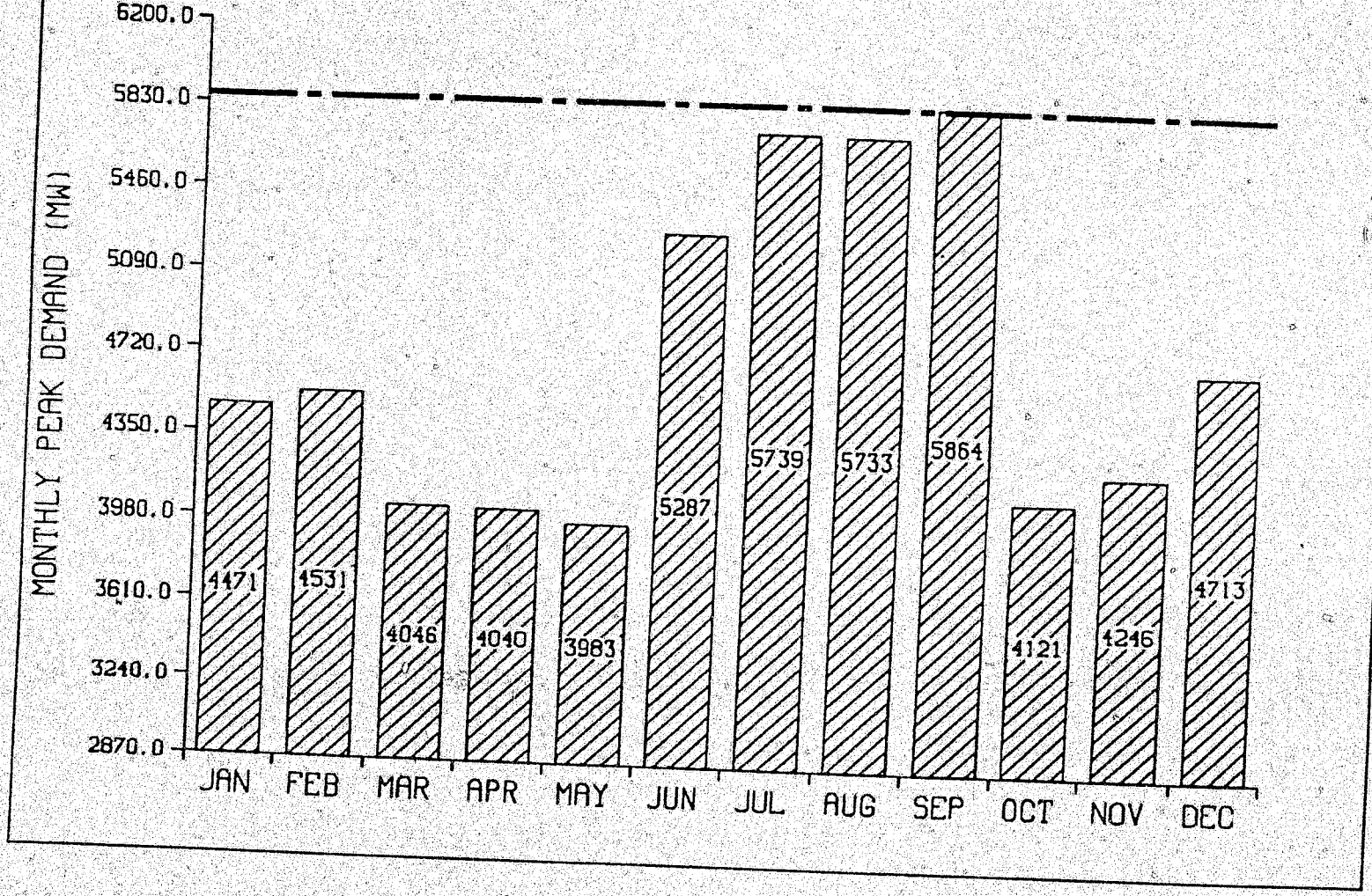


Appendix B
Chart 3

PHILADELPHIA ELECTRIC COMPANY

ANALYSIS OF MONTHLY PEAK DEMANDS

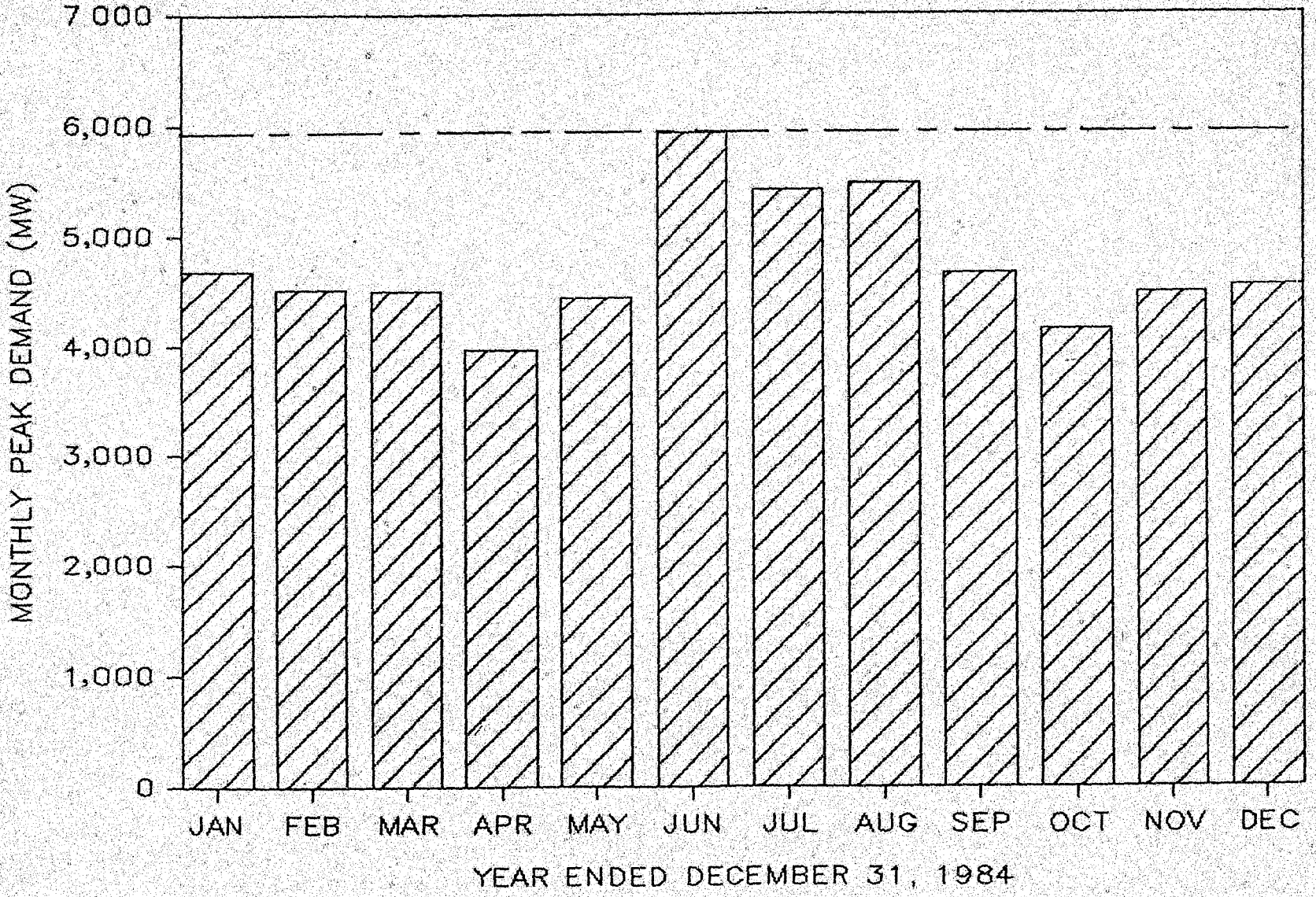
YEAR ENDED DECEMBER 31, 1983



Appendix B
Chart 4

PHILADELPHIA ELECTRIC COMPANY

ANALYSIS OF MONTHLY PEAK DEMANDS



YEAR ENDED DECEMBER 31, 1984

Appendix B
Chart 5

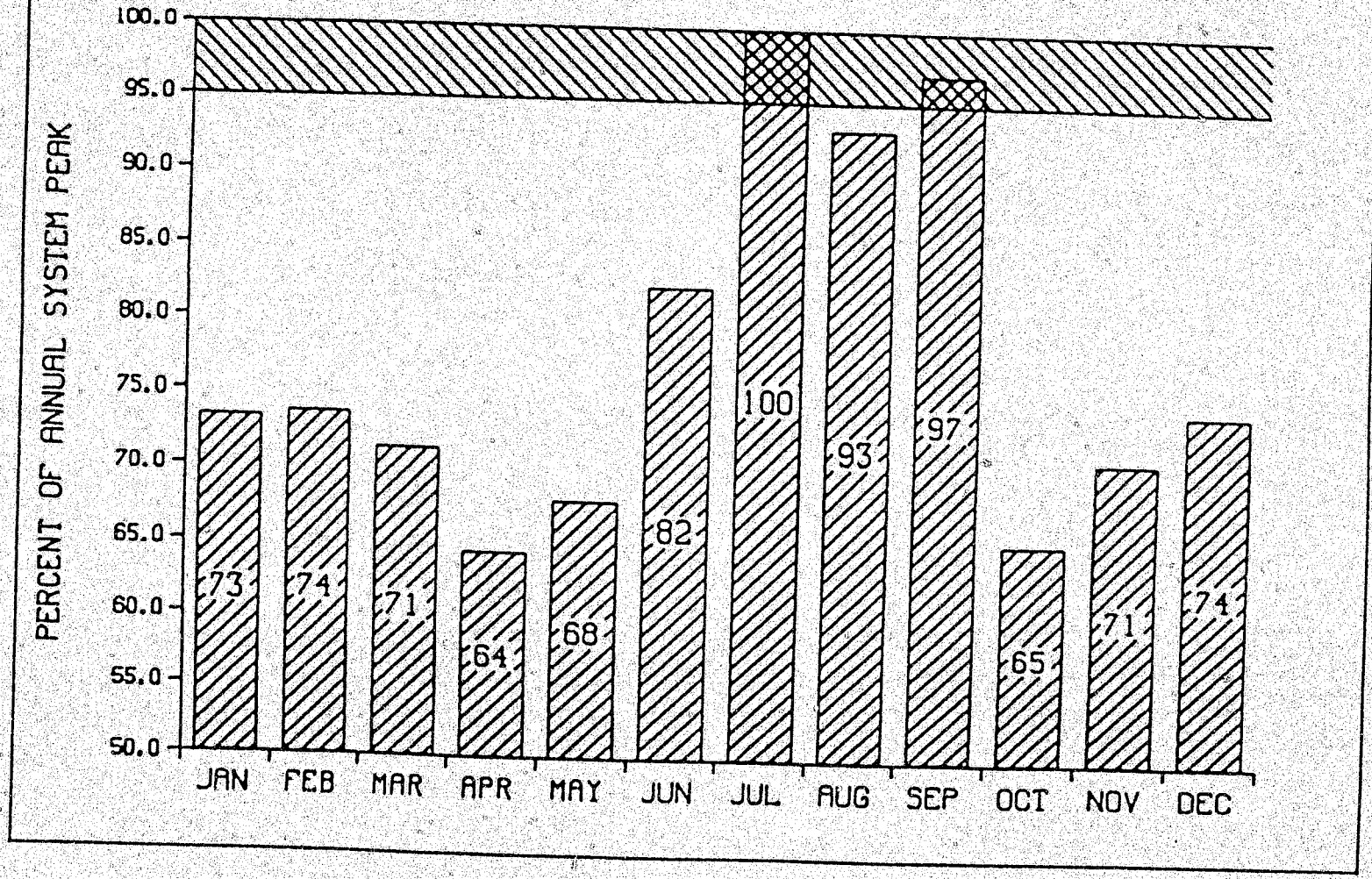
PHILADELPHIA ELECTRIC COMPANY

Monthly Peak Demands as a
Percent of the Annual System Peak

Line	Month	1979 (1)	1980 (2)	1981 (3)	1982 (4)	1983 (5)	1984 (6)
1	January	83%	73%	84%	85%	76%	79%
2	February	83	74	80	76	77	76
3	March	76	71	74	75	69	76
4	April	73	64	70	74	69	67
5	May	81	68	78	73	68	75
6	June	88	82	96	83	90	100
7	July	96	100	100	100	98	91
8	August	100	93	93	91	98	92
9	September	94	97	85	81	100	79
10	October	73	65	68	70	70	70
11	November	76	71	72	71	72	76
12	December	82	74	77	77	80	77
13	Ratio of Maximum to Minimum Monthly Peak	1.38	1.55	1.47	1.43	1.47	1.49
14	Ratio of Maximum to Average Monthly Peak	1.19	1.28	1.23	1.26	1.24	1.25
15	Annual Load Factor	60%	56%	60%	64%	58%	58%
16	Peak Load, MW	5,627	6,080	5,716	5,677	5,864	5,925

PHILADELPHIA ELECTRIC COMPANY

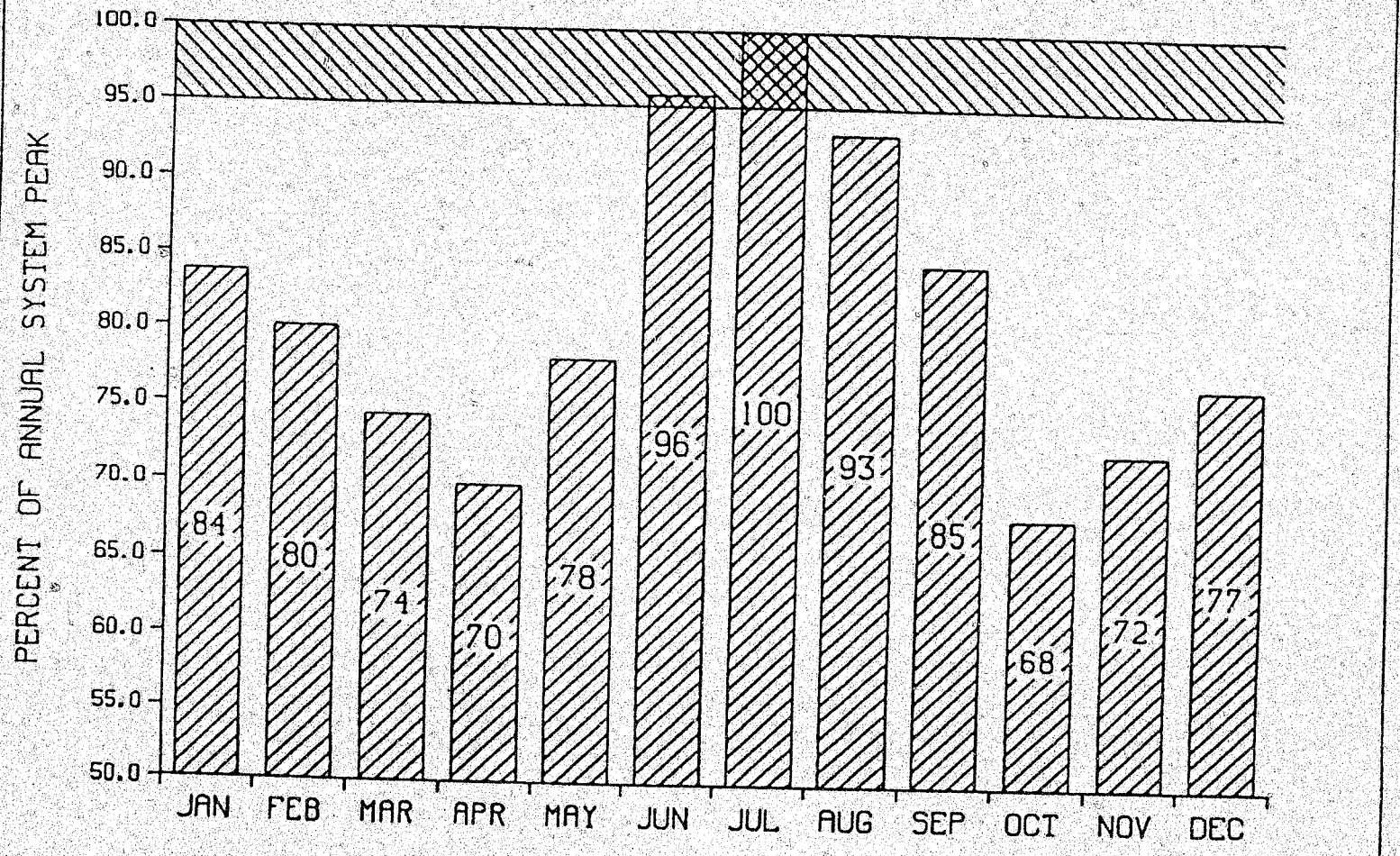
ANALYSIS OF MONTHLY PEAK DEMANDS AS A PERCENT OF ANNUAL SYSTEM PEAK YEAR ENDED DECEMBER 31, 1980



Appendix B
Chart 6

PHILADELPHIA ELECTRIC COMPANY

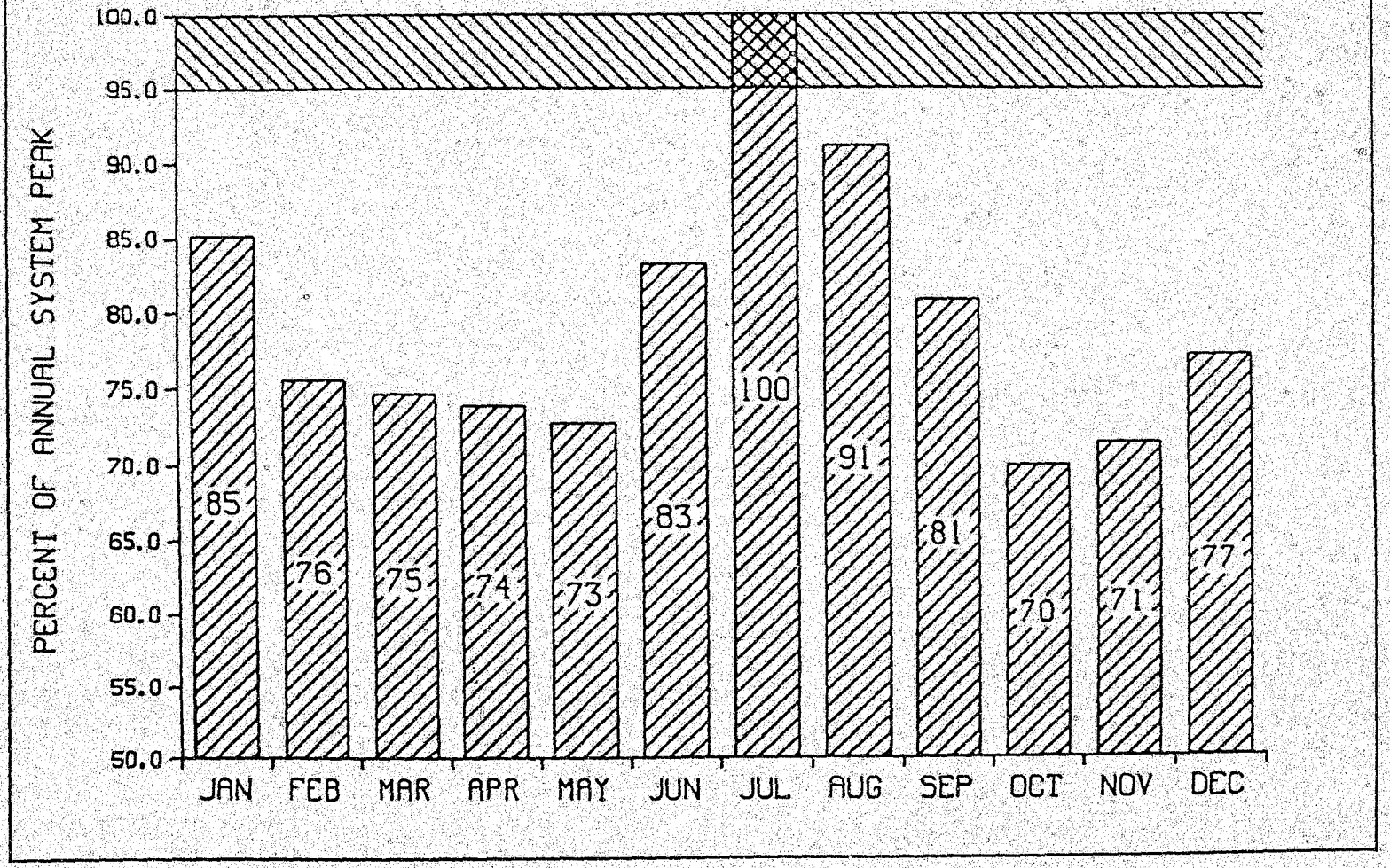
ANALYSIS OF MONTHLY PEAK DEMANDS
AS A PERCENT OF THE ANNUAL SYSTEM PEAK
YEAR ENDED DECEMBER 31, 1981



Appendix B
Chart 7

PHILADELPHIA ELECTRIC COMPANY

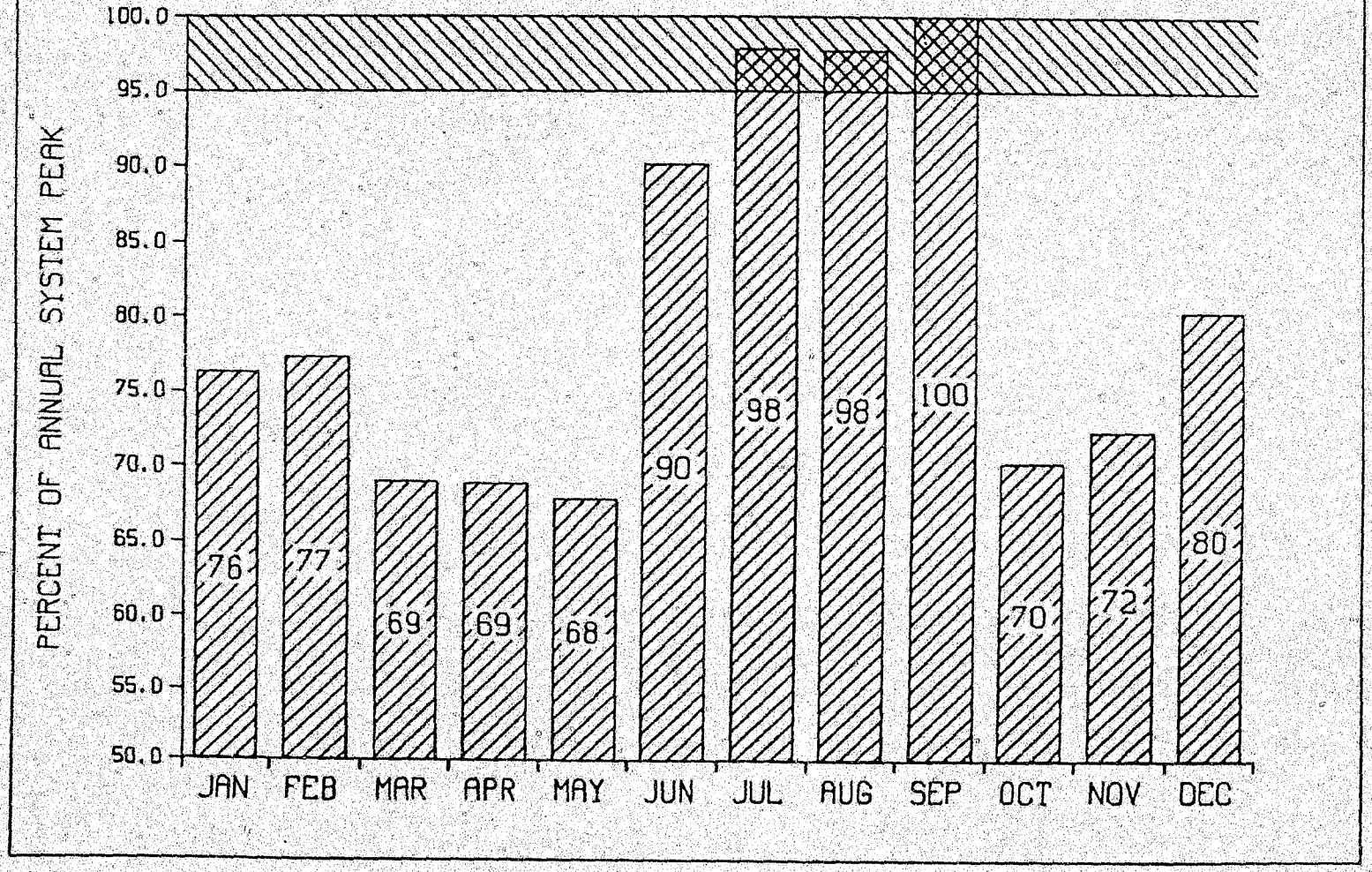
ANALYSIS OF MONTHLY PEAK DEMANDS
AS A PERCENT OF THE ANNUAL SYSTEM PEAK
YEAR ENDED DECEMBER 31, 1982



Appendix B
Chart 8

PHILADELPHIA ELECTRIC COMPANY

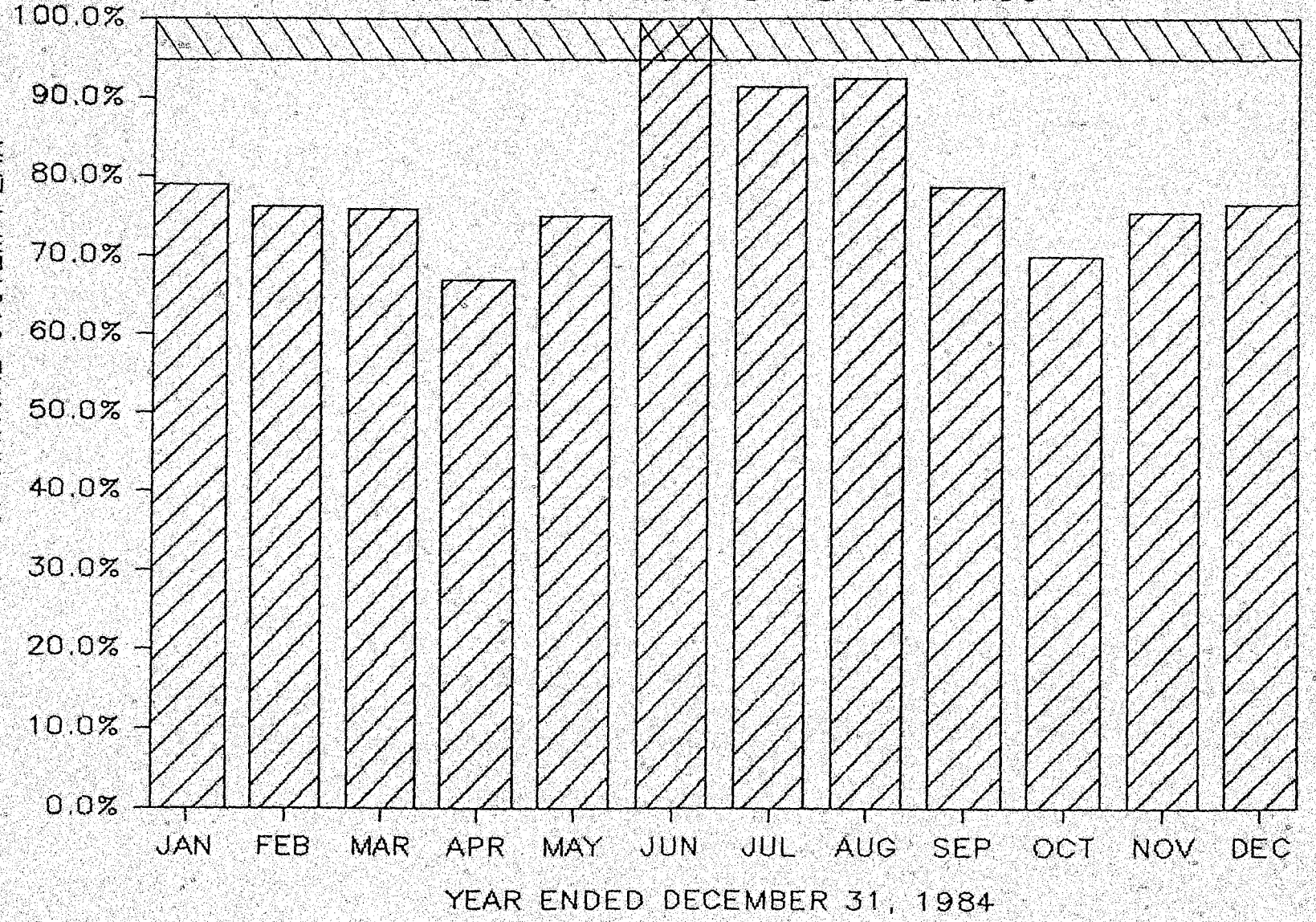
ANALYSIS OF MONTHLY PEAK DEMANDS
AS A PERCENT OF THE ANNUAL SYSTEM PEAK
YEAR ENDED DECEMBER 31, 1983



Appendix B
Chart 9

PHILADELPHIA ELECTRIC COMPANY

ANALYSIS OF MONTHLY PEAK DEMANDS

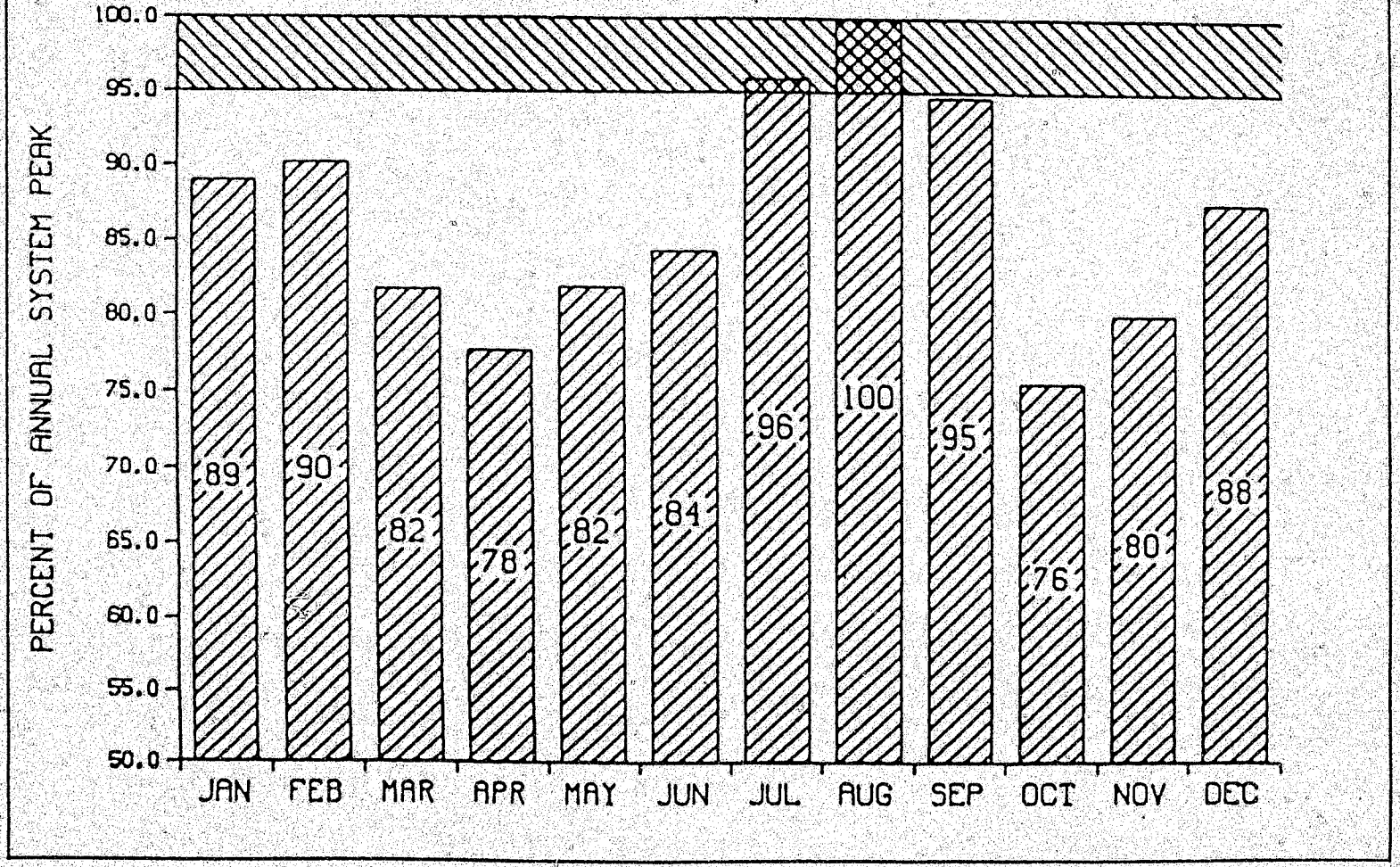


YEAR ENDED DECEMBER 31, 1984

Appendix B
Chart 10

PJM INTERCONNECTION

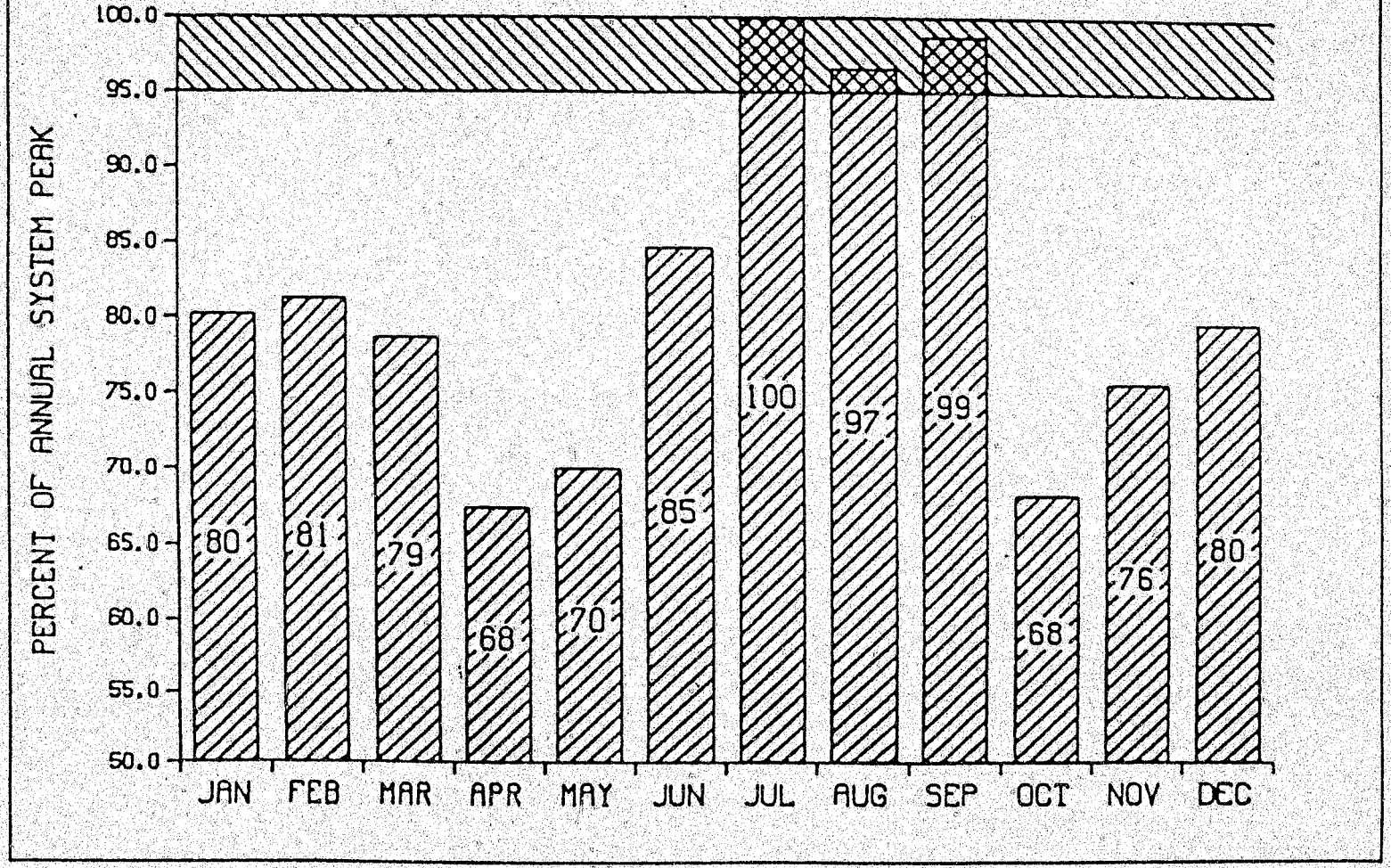
ANALYSIS OF MONTHLY PEAK DEMANDS AS A PERCENT OF THE ANNUAL SYSTEM PEAK YEAR ENDED DECEMBER 31, 1979



Appendix B
Chart 11

PJM INTERCONNECTION

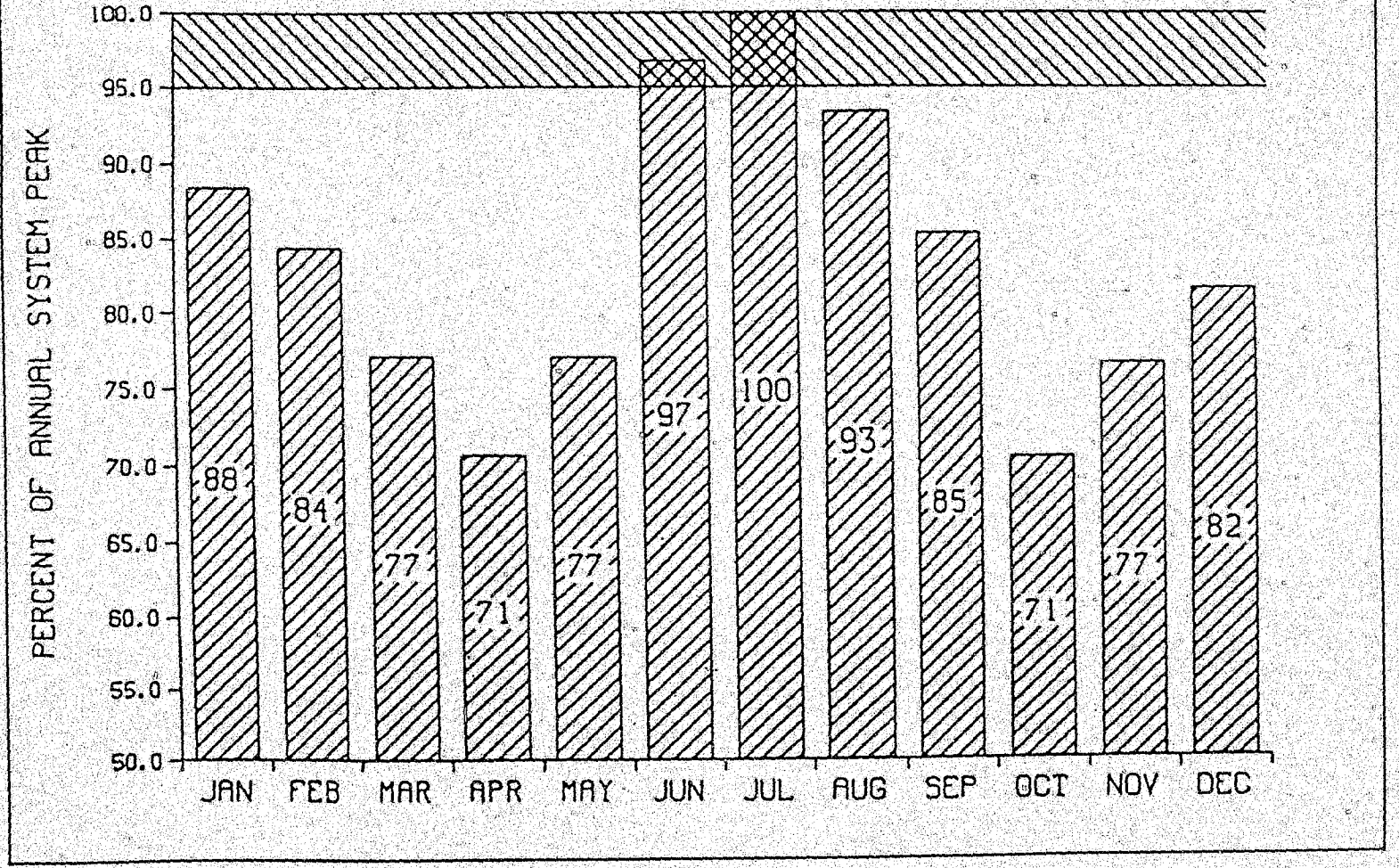
ANALYSIS OF MONTHLY PEAK DEMANDS
AS A PERCENT OF THE ANNUAL SYSTEM PEAK
YEAR ENDED DECEMBER 31, 1980



Appendix B
Chart 12

PJM INTERCONNECTION

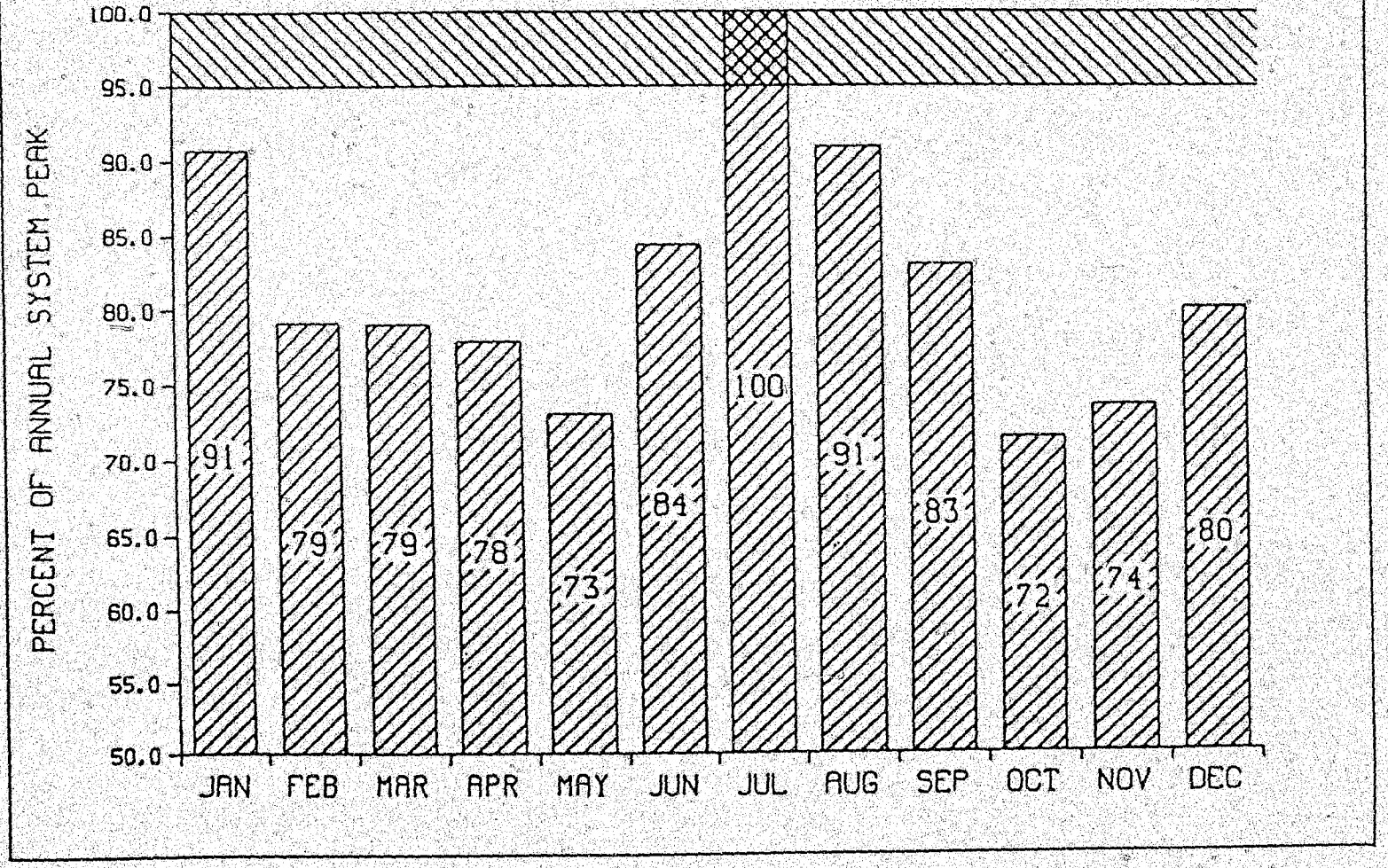
ANALYSIS OF MONTHLY PEAK DEMANDS
AS A PERCENT OF THE ANNUAL SYSTEM PEAK
YEAR ENDED DECEMBER 31, 1981



Appendix B
Chart 13

PJM INTERCONNECTION

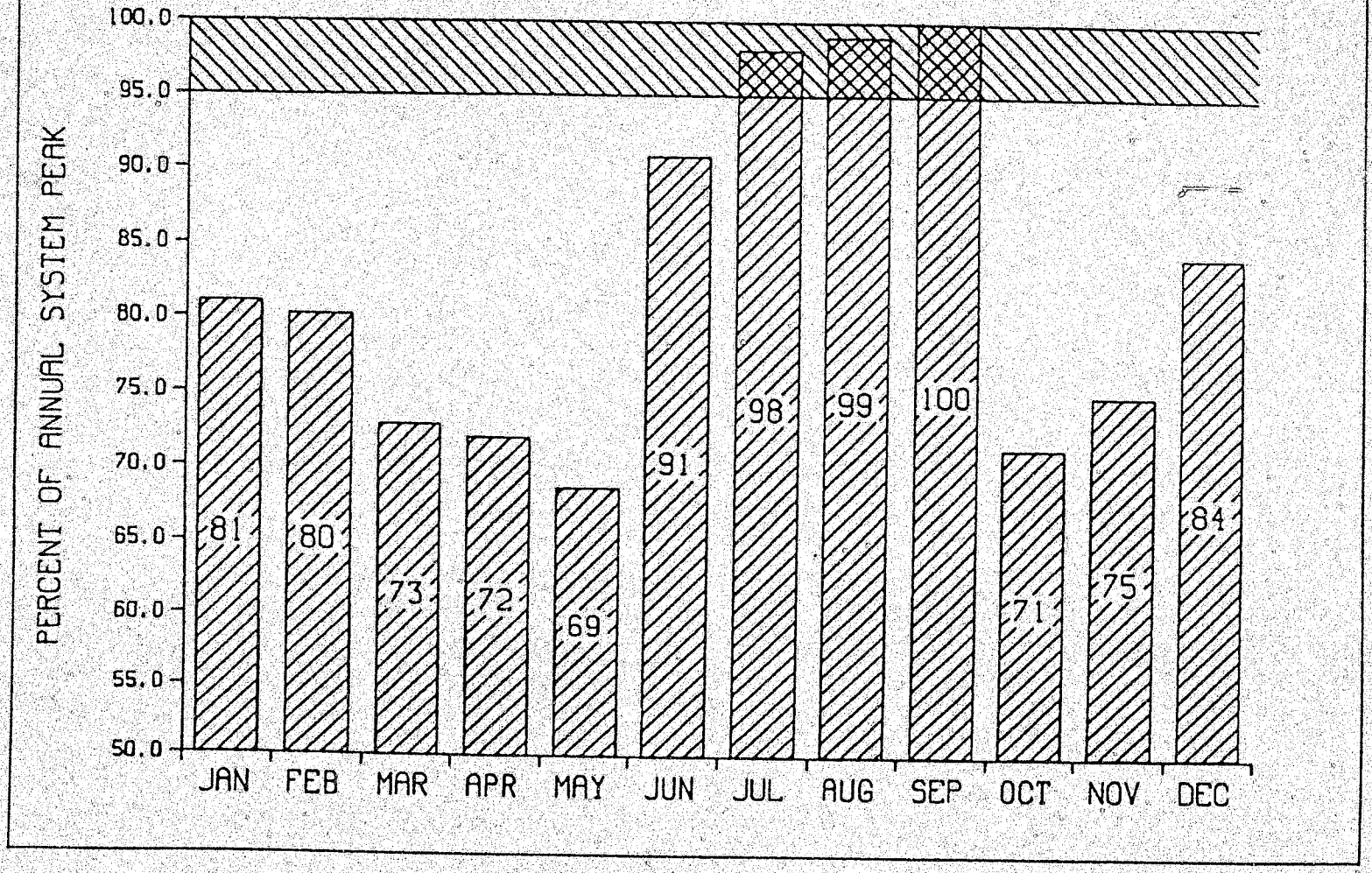
ANALYSIS OF MONTHLY PEAK DEMANDS
AS A PERCENT OF THE ANNUAL SYSTEM PEAK
YEAR ENDED DECEMBER 31, 1982



Appendix B
Chart 14

PJM INTERCONNECTION

ANALYSIS OF MONTHLY PEAK DEMANDS
AS A PERCENT OF THE ANNUAL SYSTEM PEAK
YEAR ENDED DECEMBER 31, 1983



Appendix B
Chart 15

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1979

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	44,698	44,660	44,643	44,613	44,613	44,613	44,613	44,613	44,613	44,623	44,631	44,631
System Demand (MW)	28,171	28,529	25,883	24,634	25,955	26,730	30,371	31,654	29,957	23,970	25,385	27,732
Reserve Margin (MW)	16,527	16,131	18,760	19,979	18,658	17,883	14,242	12,959	14,656	20,653	19,246	16,899
Reserve Margin as a Percent of System Demand	58.7%	56.5%	72.5%	81.1%	71.9%	66.9%	46.9%	40.9%	48.9%	86.2%	75.8%	60.9%

ce: Form 12-E-2 Reports.

Appendix B
Schedule 2
Page 1 of 6

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1980

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	44,492	44,499	44,498	44,496	44,496	44,715	44,752	44,753	44,753	44,994	44,994	44,994
System Demand (MW)	27,621	27,967	27,100	23,243	24,130	29,153	34,420	33,247	33,972	23,533	26,072	27,448
Reserve Margin (MW)	16,871	16,532	17,398	21,253	20,366	15,562	10,332	11,506	10,781	21,461	18,922	17,546
Reserve Margin as a Percent of System Demand	61.1%	59.1%	64.2%	91.4%	84.4%	53.4%	30.0%	34.6%	31.7%	91.2%	72.6%	63.9%

rce: Form 12-E-2 Reports.

Appendix B
Schedule 2
Page 2 of 6

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1981

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	44,900	44,870	44,828	44,840	44,840	44,625	44,627	44,627	44,627	45,393	45,393	45,393
System Demand (MW)	29,625	28,313	25,870	23,715	25,853	32,448	33,528	31,292	28,608	23,680	25,735	27,393
Reserve Margin (MW)	15,275	16,557	18,958	21,125	18,987	12,177	11,099	13,335	16,019	21,713	19,658	18,000
Reserve Margin as a Percent of System Demand	51.6%	58.5%	73.3%	89.1%	73.4%	37.5%	33.1%	42.6%	56.0%	91.7%	76.4%	65.7%

e: ERA Form 119-M.

Appendix B
Schedule 2
Page 3 of 6

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1982

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	45,570	45,547	45,859	45,859	45,781	45,781	45,796	45,796	45,772	45,783	45,774	45,774
System Demand (MW)	30,621	26,734	26,683	26,302	24,685	28,469	33,741	30,668	28,042	24,147	24,883	27,062
Reserve Margin (MW)	14,949	18,813	19,176	19,557	21,096	17,312	12,055	15,128	17,730	21,636	20,891	18,712
Reserve Margin as a Percent of System Demand	48.8%	70.4%	71.9%	74.4%	85.5%	60.8%	35.7%	49.3%	63.2%	89.6%	84.0%	69.1%

e: ERA Form 119-M.

Appendix B
Schedule 2
Page 4 of 6

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1983

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	45,794	45,794	45,802	45,814	45,814	46,864	46,712	46,704	46,704	46,734	46,734	47,056
System Demand (MW)	28,092	27,813	25,278	24,994	23,786	31,520	34,021	34,346	34,678	24,742	25,922	29,241
Reserve Margin (MW)	17,702	17,981	20,524	20,820	22,028	15,344	12,691	12,358	12,026	21,992	20,812	17,815
Reserve Margin as a Percent of System Demand	63.0%	64.6%	81.2%	83.3%	92.6%	48.7%	37.3%	36.0%	34.7%	88.9%	80.3%	60.9%

e: IR-PAIEUG-1-3.

Appendix B
Schedule 2
Page 5 of 6

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1984

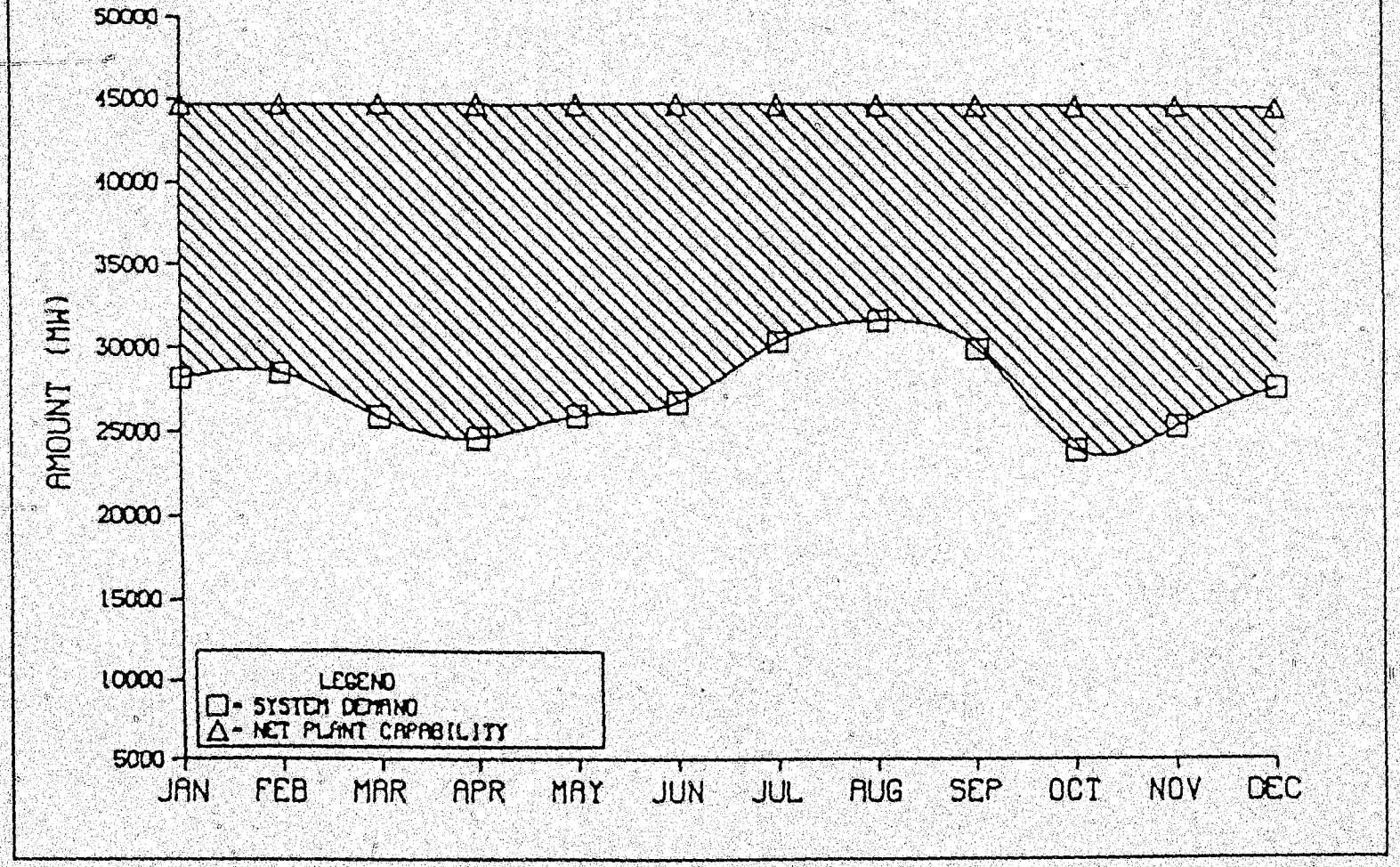
Line	Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
1	Net Plant Capability (MW)	48,604	48,509	48,367	48,285	48,057	45,899	46,833	46,190	47,371	47,034	47,639	47,652
2	System Demand (MW)	29,658	28,332	28,261	24,704	26,486	35,319	33,013	33,229	28,694	25,239	27,786	28,539
3	Reserve Margin (MW)	18,946	20,177	20,106	23,581	21,571	10,580	13,820	12,961	18,677	21,795	19,853	19,113
4	Reserve Margin as a Percent of System Demand	64.0%	71.2%	71.1%	96.0%	81.4%	30.0%	42.0%	39.0%	65.1%	86.4%	71.4%	67.0%

Appendix B
Schedule 2
Page 6 of 6

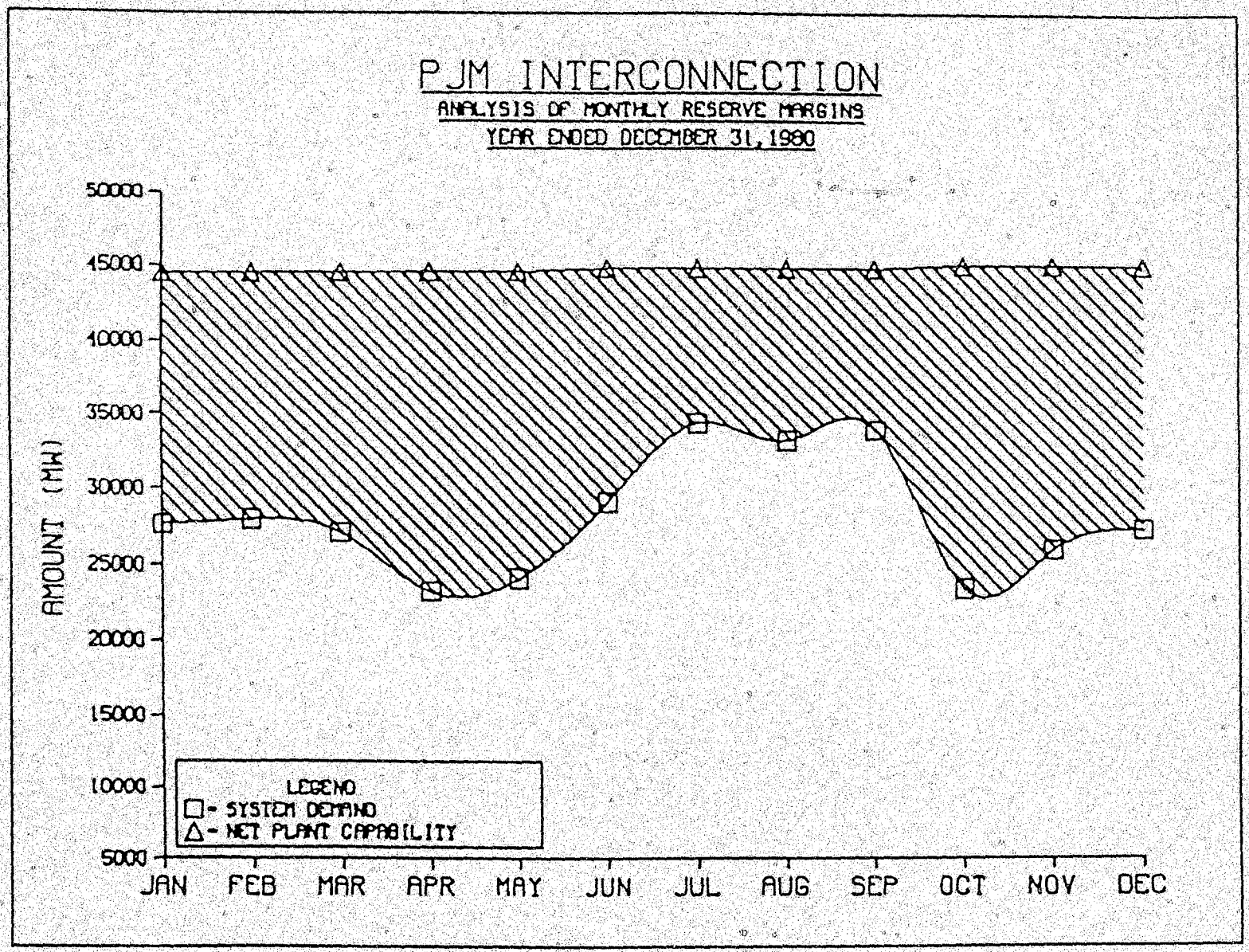
PJM INTERCONNECTION

ANALYSIS OF MONTHLY RESERVE MARGINS

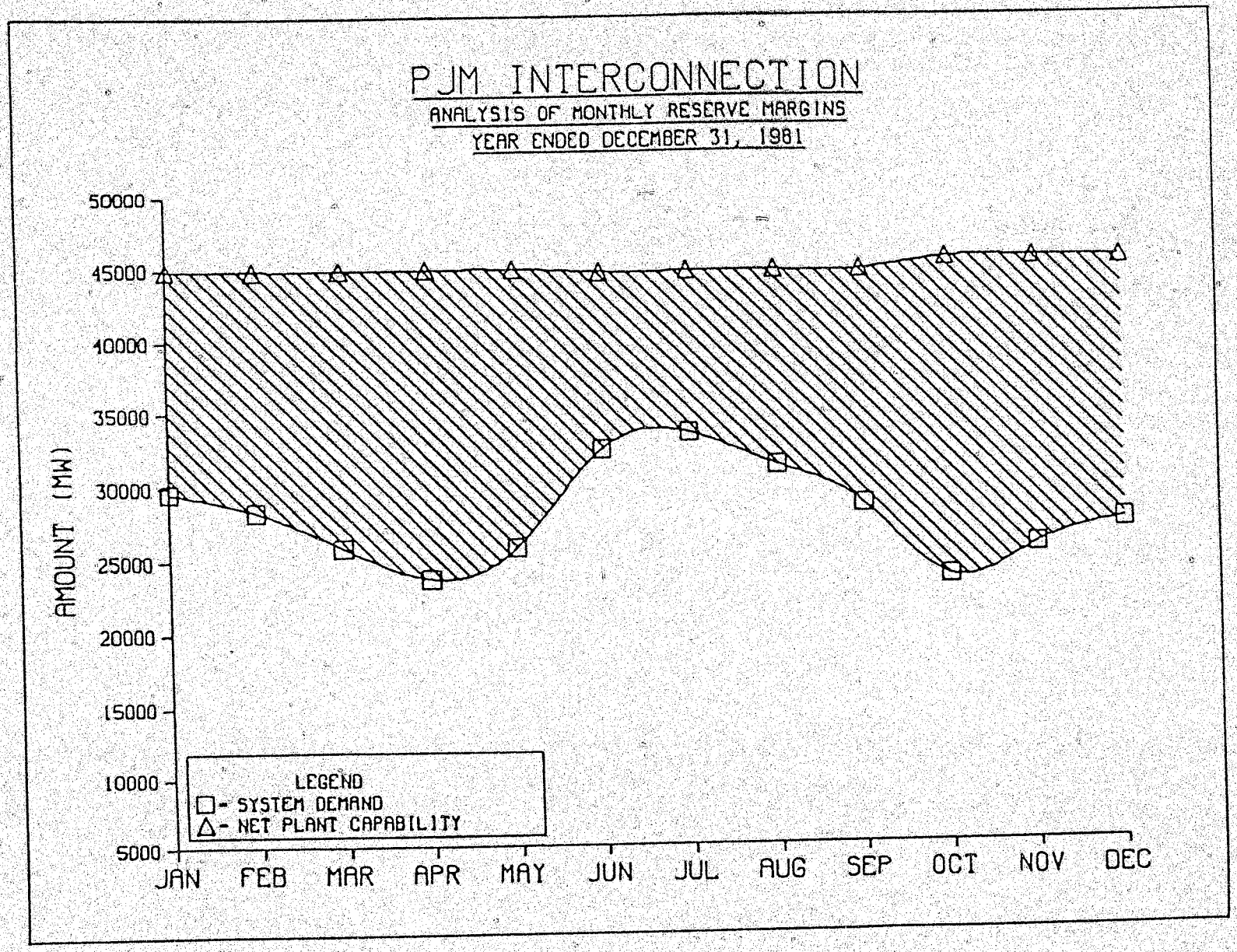
YEAR ENDED DECEMBER 31, 1979



Appendix B
Chart 16



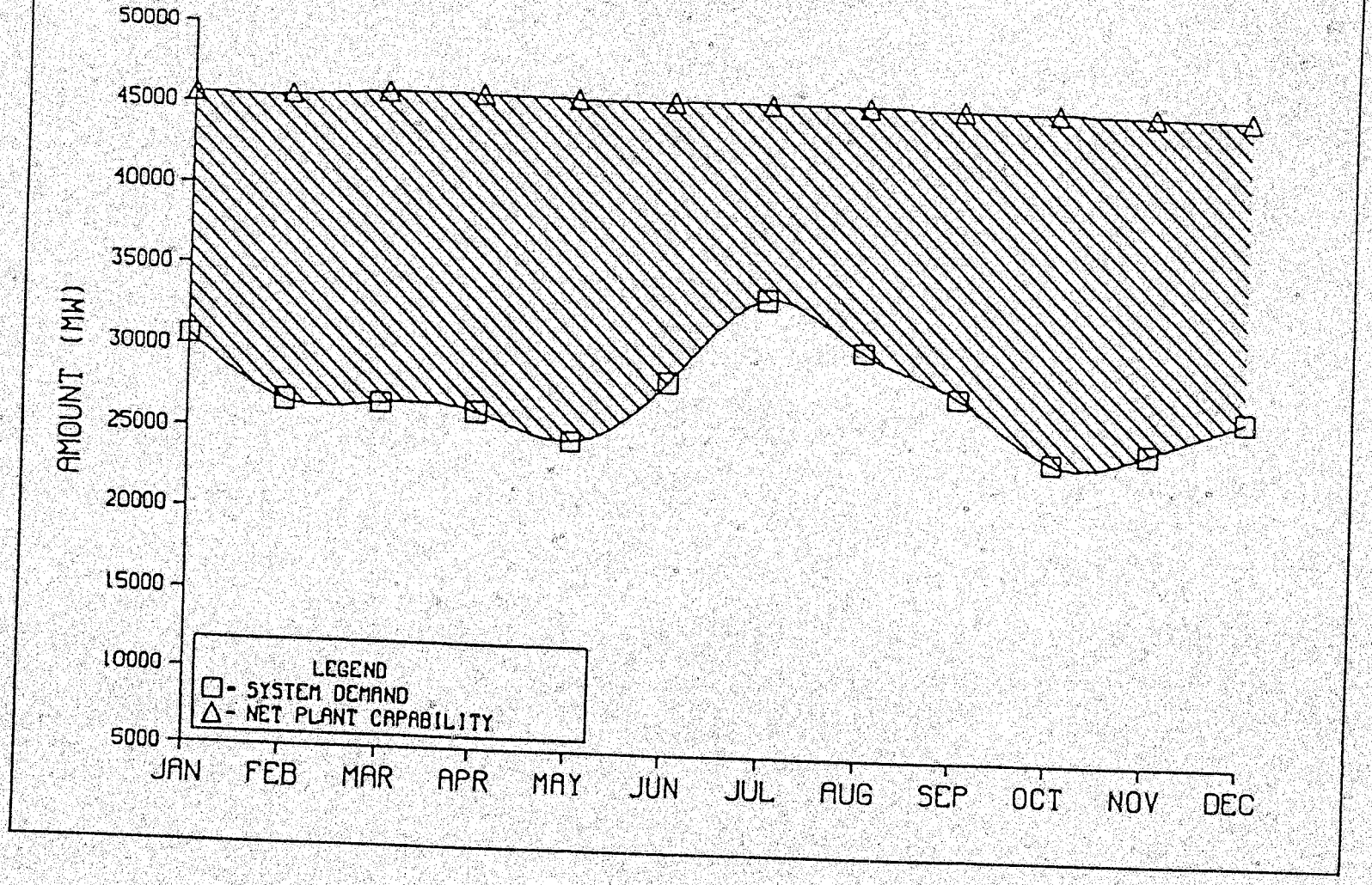
Appendix B
Chart 17



Appendix B
Chart 18

PJM INTERCONNECTION

ANALYSIS OF MONTHLY RESERVE MARGINS
YEAR ENDED DECEMBER 31, 1982

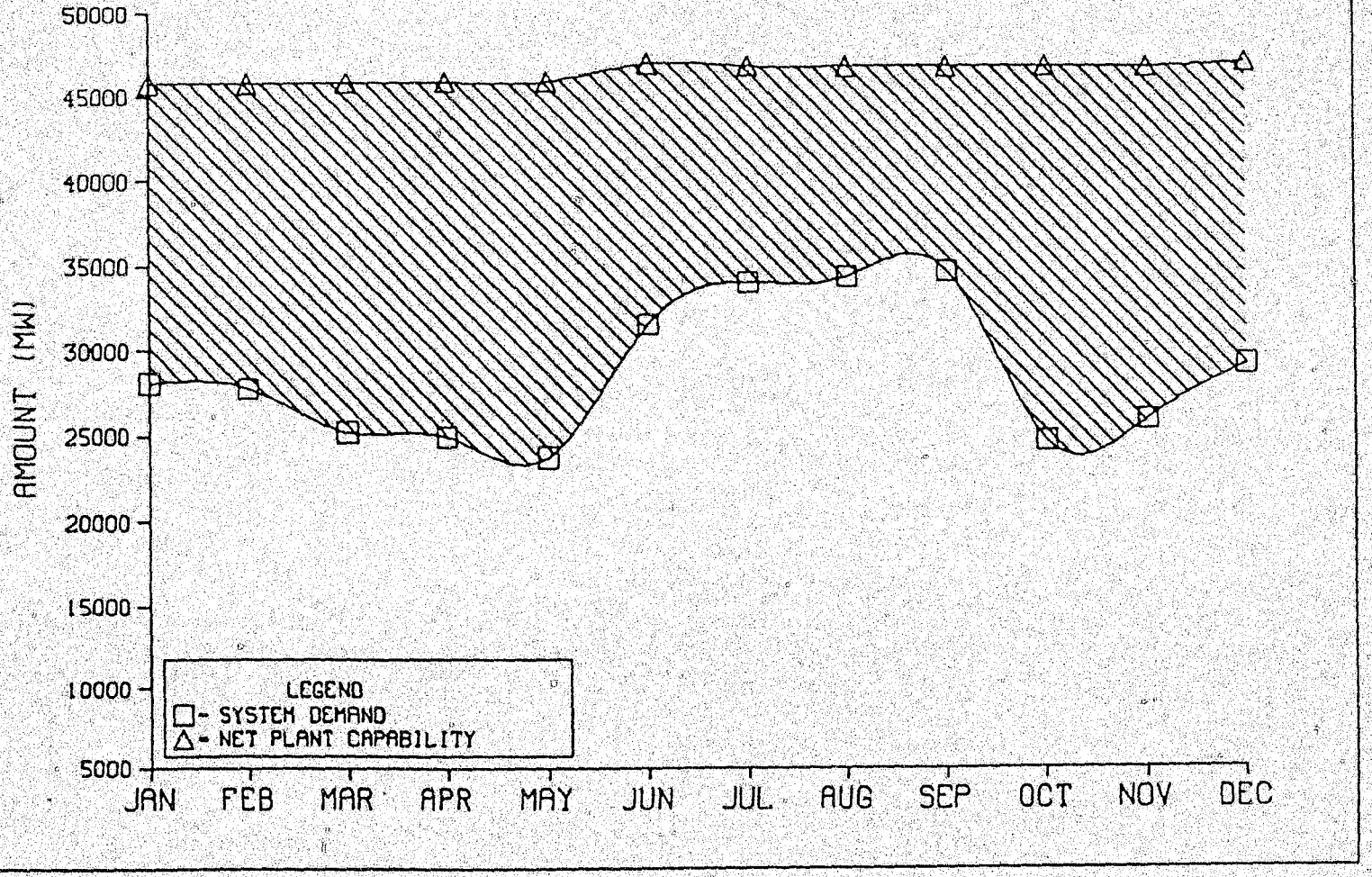


Appendix B
Chart 19

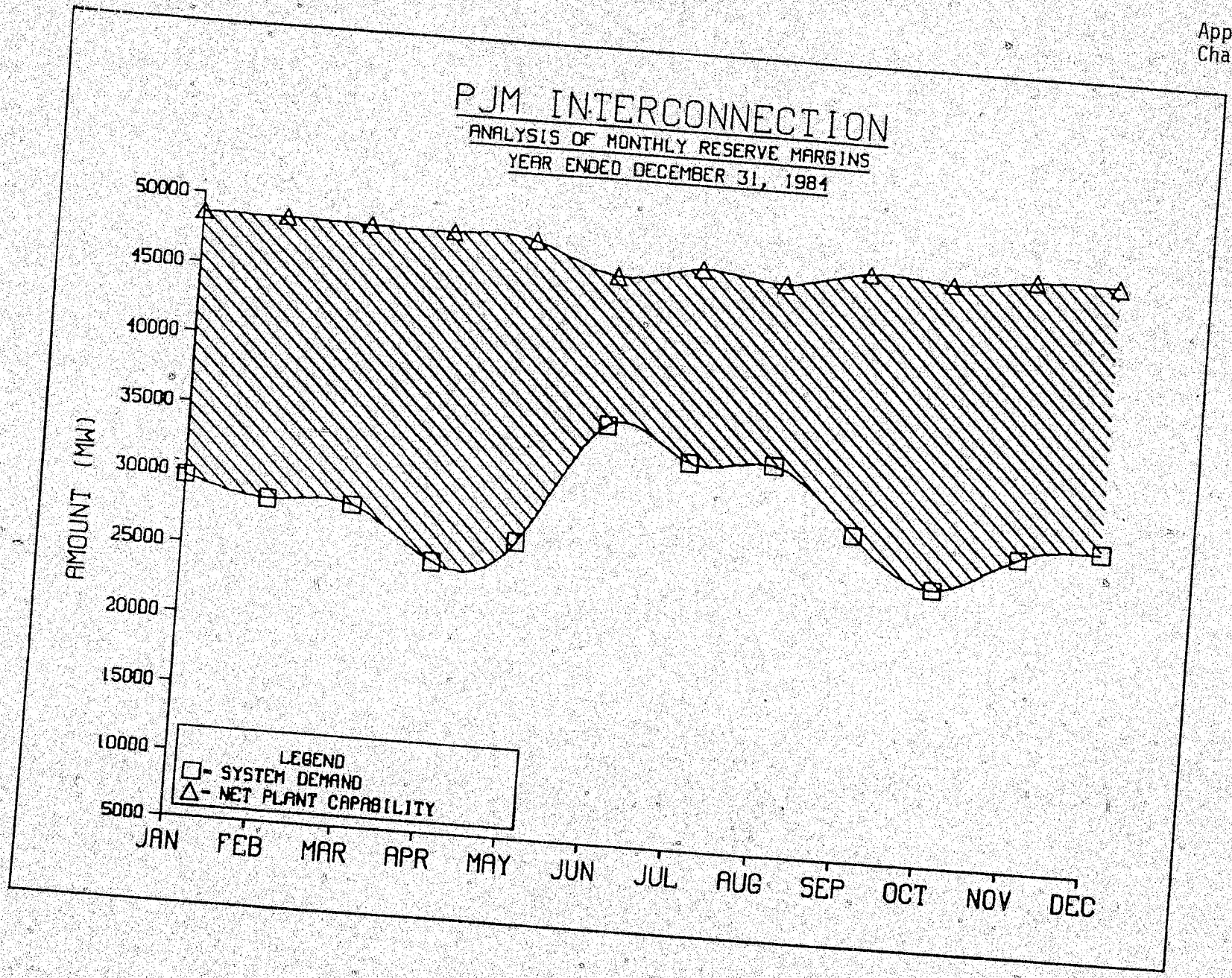
PJM INTERCONNECTION

ANALYSIS OF MONTHLY RESERVE MARGINS

YEAR ENDED DECEMBER 31, 1983



Appendix B
Chart 20



Appendix B
Chart 21

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1979
with Adjustments for Scheduled Maintenance

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	44,698	44,660	44,643	44,613	44,613	44,613	44,613	44,613	44,613	44,623	44,631	44,631
Scheduled Maintenance (MW)	3,516	4,689	6,547	7,311	5,991	2,938	1,182	1,459	1,118	4,547	4,110	4,069
Adjusted Capability (MW)	41,182	39,971	38,096	37,302	38,622	41,675	43,431	43,154	43,495	40,076	40,521	40,562
System Demand (MW)	28,171	28,529	25,883	24,634	25,955	26,730	30,371	31,654	29,957	23,970	25,385	27,732
Capacity Margin (MW)	13,011	11,442	12,213	12,668	12,667	14,945	13,060	11,500	13,538	16,106	15,136	12,830
Capacity Margin as a Percent of System Demand	46.2%	40.1%	47.2%	51.4%	48.8%	55.9%	43.0%	36.3%	45.2%	67.2%	59.6%	46.3%

ce: Form 12-E-2 Reports.

Appendix B
Schedule 3
Page 1 of 6

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1980
with Adjustments for Scheduled Maintenance

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	44,492	44,499	44,498	44,496	44,496	44,715	44,752	44,753	44,753	44,994	44,994	44,994
Scheduled Maintenance (MW)	5,863	5,414	5,686	5,978	7,710	3,049	1,729	1,674	2,043	8,529	7,147	5,414
Adjusted Capability (MW)	38,629	39,085	38,812	38,518	36,786	41,666	43,023	43,079	42,710	36,465	37,847	39,580
System Demand (MW)	27,621	27,967	27,100	23,243	24,130	29,153	34,420	33,247	33,972	23,533	26,072	27,448
Capacity Margin (MW)	11,008	11,118	11,712	15,275	12,656	12,513	8,603	9,832	8,738	12,932	11,775	12,132
Capacity Margin as a Percent of System Demand	39.9%	39.8%	43.2%	65.7%	52.4%	42.9%	25.0%	29.6%	25.7%	55.0%	45.2%	44.2%

e: Form 12-E-2 Reports.

Appendix B
Schedule 3
Page 2 of 6

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1981
with Adjustments for Scheduled Maintenance

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	44,900	44,870	44,828	44,840	44,840	44,625	44,627	44,627	44,627	45,393	45,393	45,393
Scheduled Maintenance (MW)	3,871	4,308	7,834	6,268	8,307	3,931	1,710	1,908	4,147	5,704	5,172	4,546
Adjusted Capability (MW)	41,029	40,562	36,994	38,572	36,533	40,694	42,917	42,719	40,480	39,689	40,221	40,847
System Demand (MW)	29,625	28,313	25,870	23,715	25,853	32,448	33,528	31,292	28,608	23,680	25,735	27,393
Capacity Margin (MW)	11,404	12,249	11,124	14,857	10,680	8,246	9,389	11,427	11,872	16,009	14,486	13,454
Capacity Margin as a Percent of System Demand	38.5%	43.3%	43.0%	62.6%	41.3%	25.4%	28.0%	36.5%	41.5%	67.6%	56.3%	49.1%

ce: ERA Form 119-M.

Appendix B
Schedule 3
Page 3 of 6

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1982
with Adjustments for Scheduled Maintenance

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	45,570	45,547	45,859	45,859	45,781	45,781	45,796	45,796	45,772	45,783	45,774	45,774
Scheduled Maintenance (MW)	3,415	4,307	6,355	8,439	7,465	4,636	1,388	3,135	3,057	8,308	6,123	6,184
Adjusted Capability (MW)	42,155	41,240	39,504	37,420	38,316	41,145	44,408	42,661	42,715	37,475	39,651	39,590
System Demand (MW)	30,621	26,734	26,683	26,302	24,685	28,469	33,741	30,668	28,042	24,147	24,883	27,062
Capacity Margin (MW)	11,534	14,506	12,821	11,118	13,631	12,676	10,667	11,993	14,673	13,328	14,768	12,528
Capacity Margin as a Percent of System Demand	37.7%	54.3%	48.0%	42.3%	55.2%	44.5%	31.6%	39.1%	52.3%	55.2%	59.3%	46.3%

ce: ERA Form 119-M.

Appendix B
Schedule 3
Page 4 of 6

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1983
with Adjustments for Scheduled Maintenance

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	45,794	45,794	45,802	45,814	45,814	46,864	46,712	46,704	46,704	46,734	46,734	47,056
Scheduled Maintenance (MW)	6,355	6,277	7,412	9,156	9,456	7,032	4,343	3,215	3,914	8,616	6,279	5,022
Adjusted Capability (MW)	39,439	39,517	38,390	36,658	36,358	39,832	42,369	43,489	42,790	38,118	40,455	42,034
System Demand (MW)	28,092	27,813	25,278	24,994	23,786	31,520	34,021	34,346	34,678	24,742	25,922	29,241
Capacity Margin (MW)	11,347	11,704	13,112	11,664	12,572	8,312	8,348	9,143	8,112	13,376	14,533	12,793
Capacity Margin as a Percent of System Demand	40.4%	42.1%	51.9%	46.7%	52.9%	26.4%	24.5%	26.6%	23.4%	54.1%	56.1%	43.8%

ce: IR-PAIEUG-1-3.

Appendix B
Schedule 3
Page 5 of 6

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1984
with Adjustments for Scheduled Maintenance

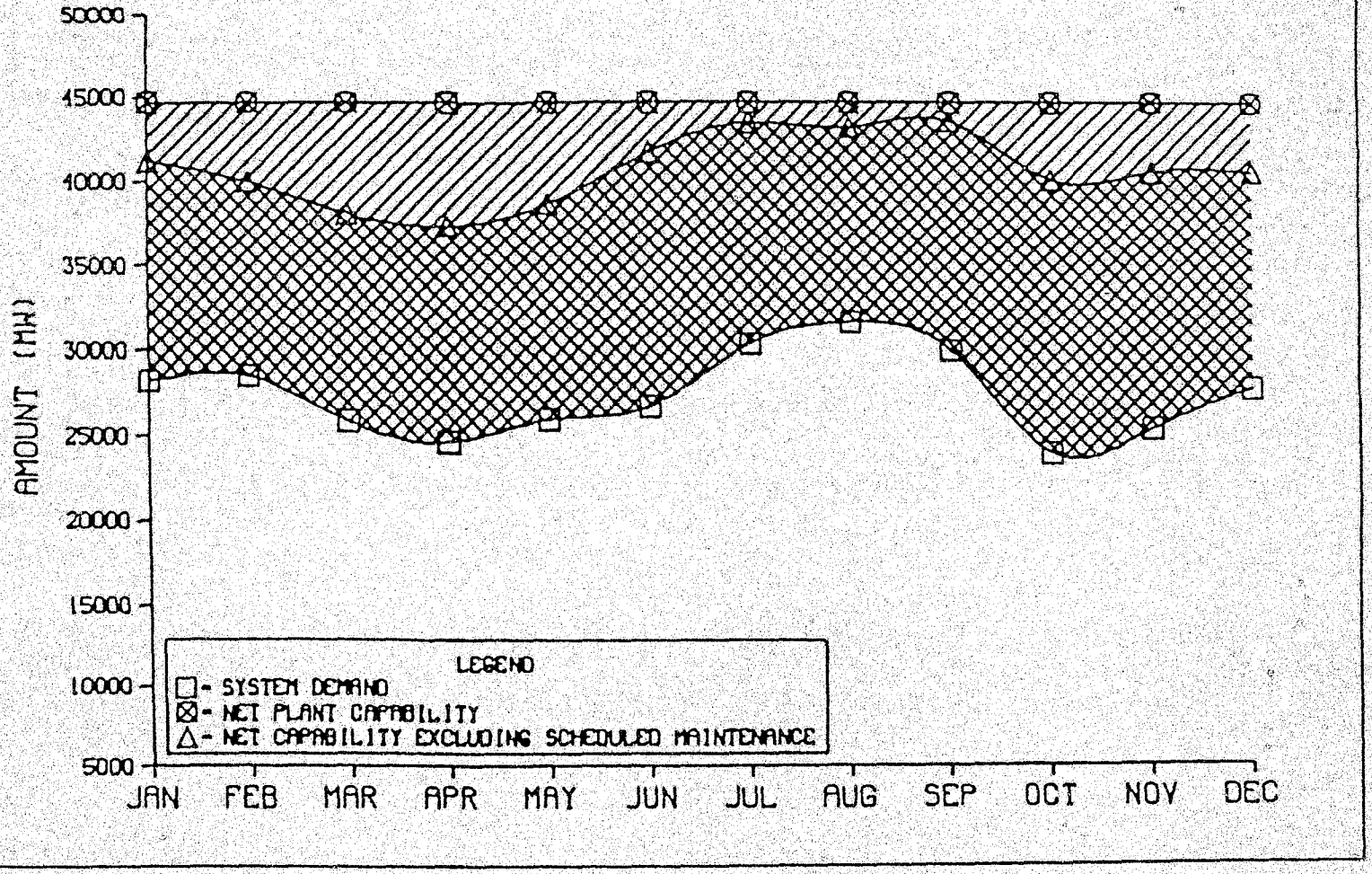
Line	Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
1	Net Plant Capability (MW)	48,604	48,509	48,367	48,285	48,057	45,899	46,833	46,190	47,371	47,034	47,639	47,652
2	Scheduled Maintenance (MW)	6,065	6,281	6,541	7,010	9,239	7,698	4,073	4,424	6,467	9,370	10,108	7,766
3	Adjusted Capability (MW)	42,539	42,228	41,826	41,275	38,818	38,201	42,760	41,766	40,904	37,664	37,531	39,886
4	System Demand (MW)	29,658	28,332	28,261	24,704	26,486	35,319	33,013	33,229	28,694	25,239	27,786	28,539
5	Capacity Margin (MW)	12,881	13,896	13,565	16,571	12,332	2,882	9,747	8,537	12,210	12,425	9,745	11,347
6	Capacity Margin as a Percent of System Demand	43.4%	49.0%	48.0%	67.1%	47.0%	8.2%	30.0%	26.0%	43.0%	49.2%	35.1%	40.0%

Appendix B
Schedule 3
Page 6 of 6

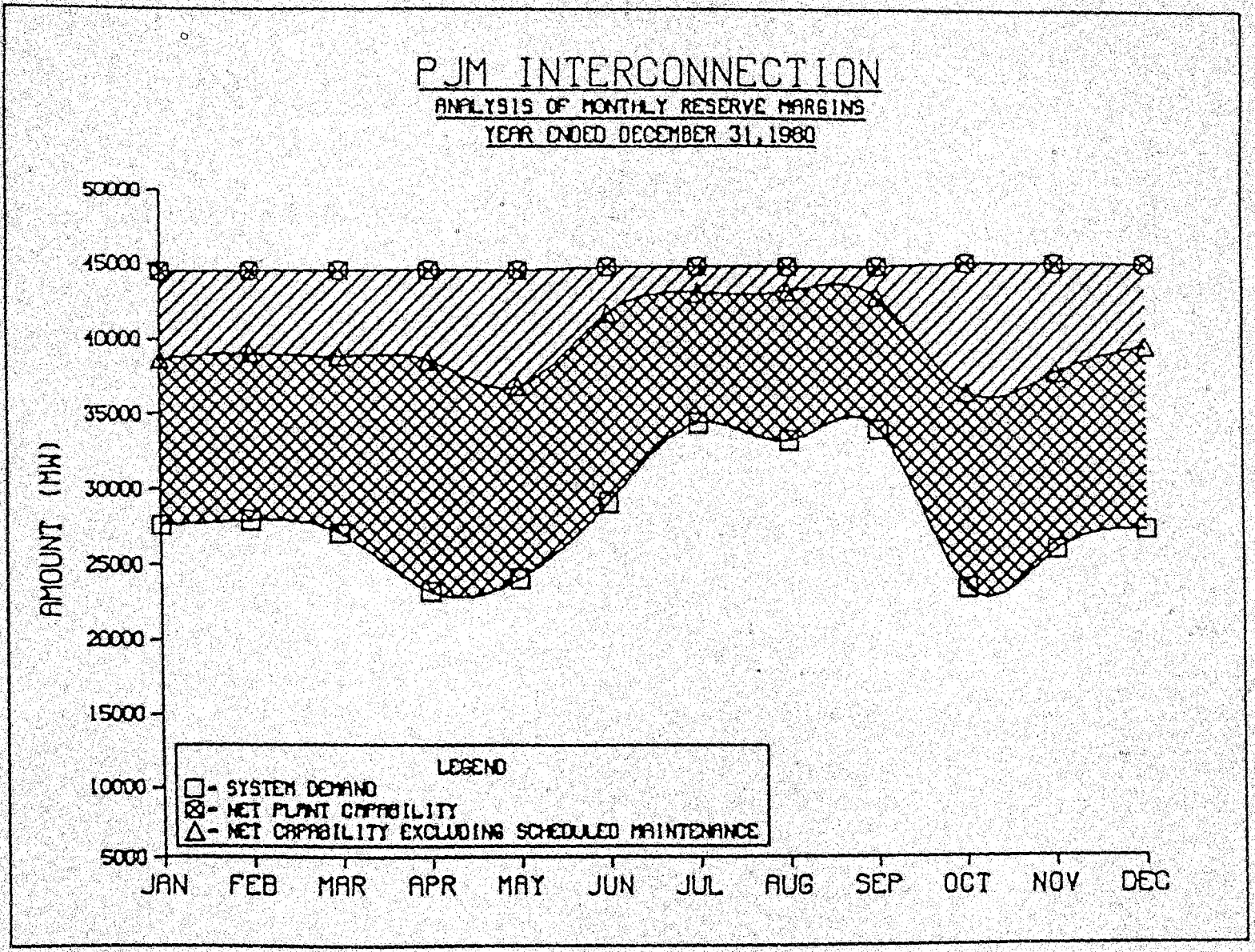
PJM INTERCONNECTION

ANALYSIS OF MONTHLY RESERVE MARGINS

YEAR ENDED DECEMBER 31, 1979



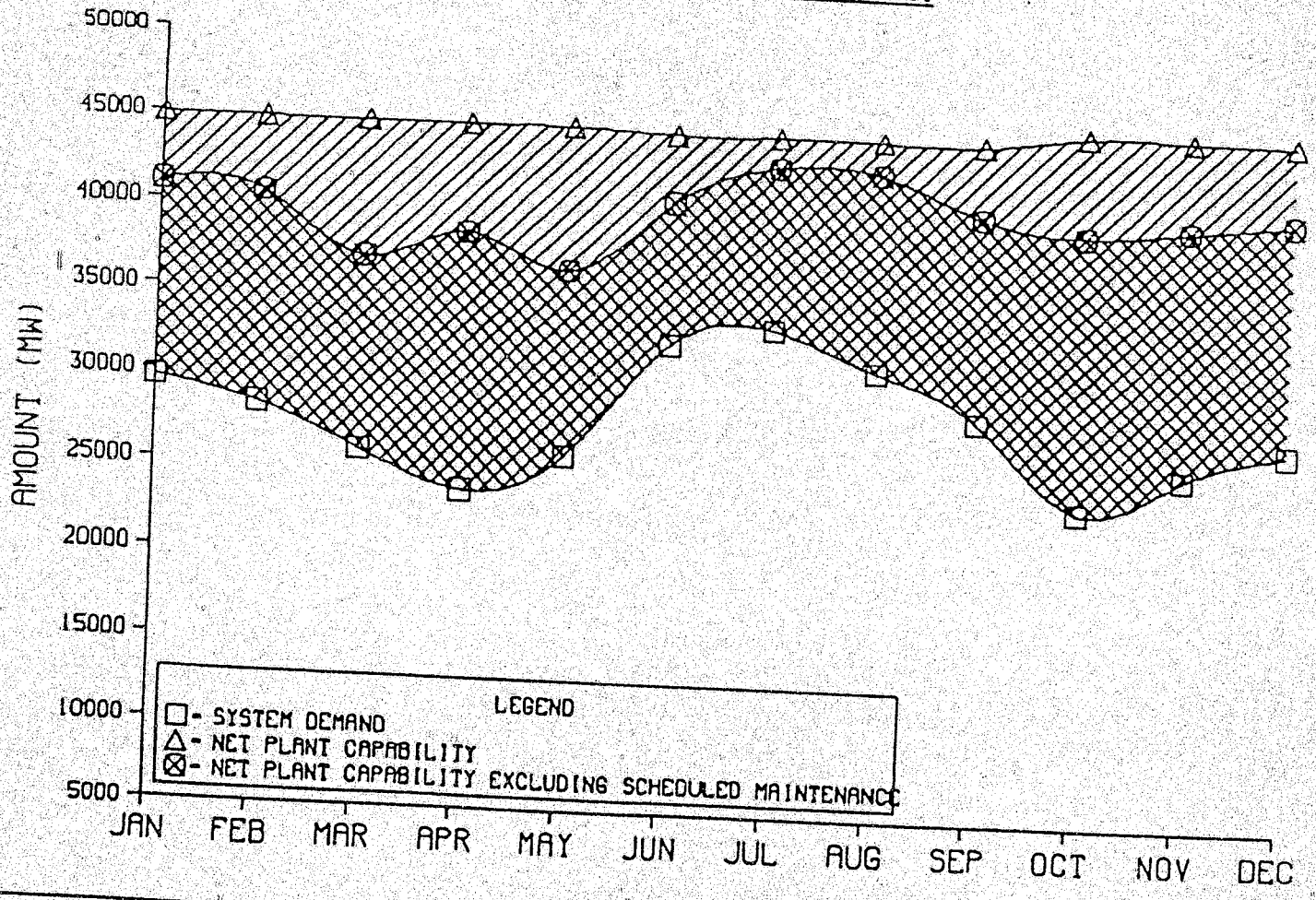
Appendix B
Chart 22



Appendix B
Chart 23

PJM INTERCONNECTION

ANALYSIS OF MONTHLY RESERVE MARGINS
YEAR ENDED DECEMBER 31, 1981

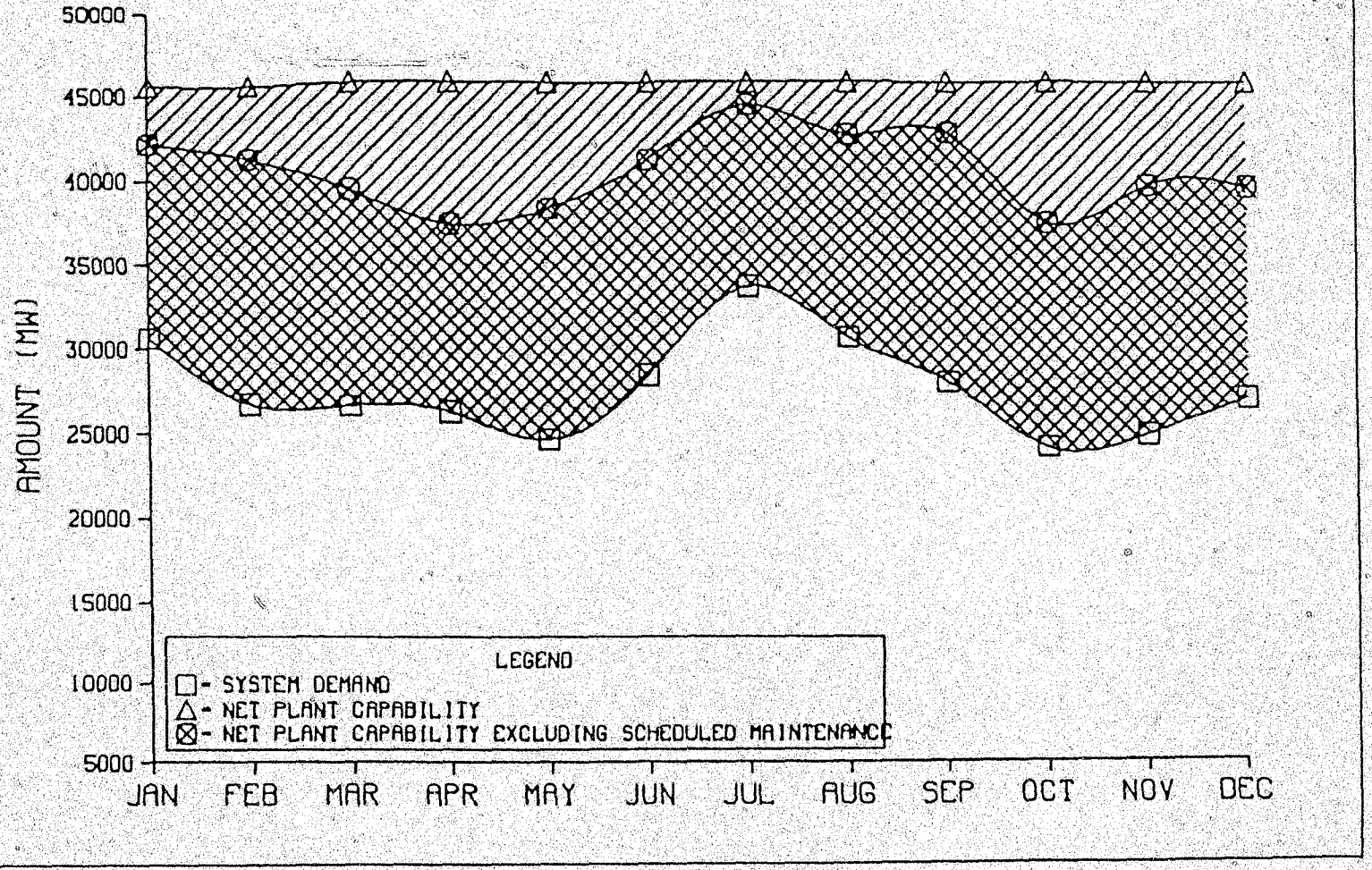


Appendix B
Chart 24

PJM INTERCONNECTION

ANALYSIS OF MONTHLY RESERVE MARGINS

YEAR ENDED DECEMBER 31, 1982

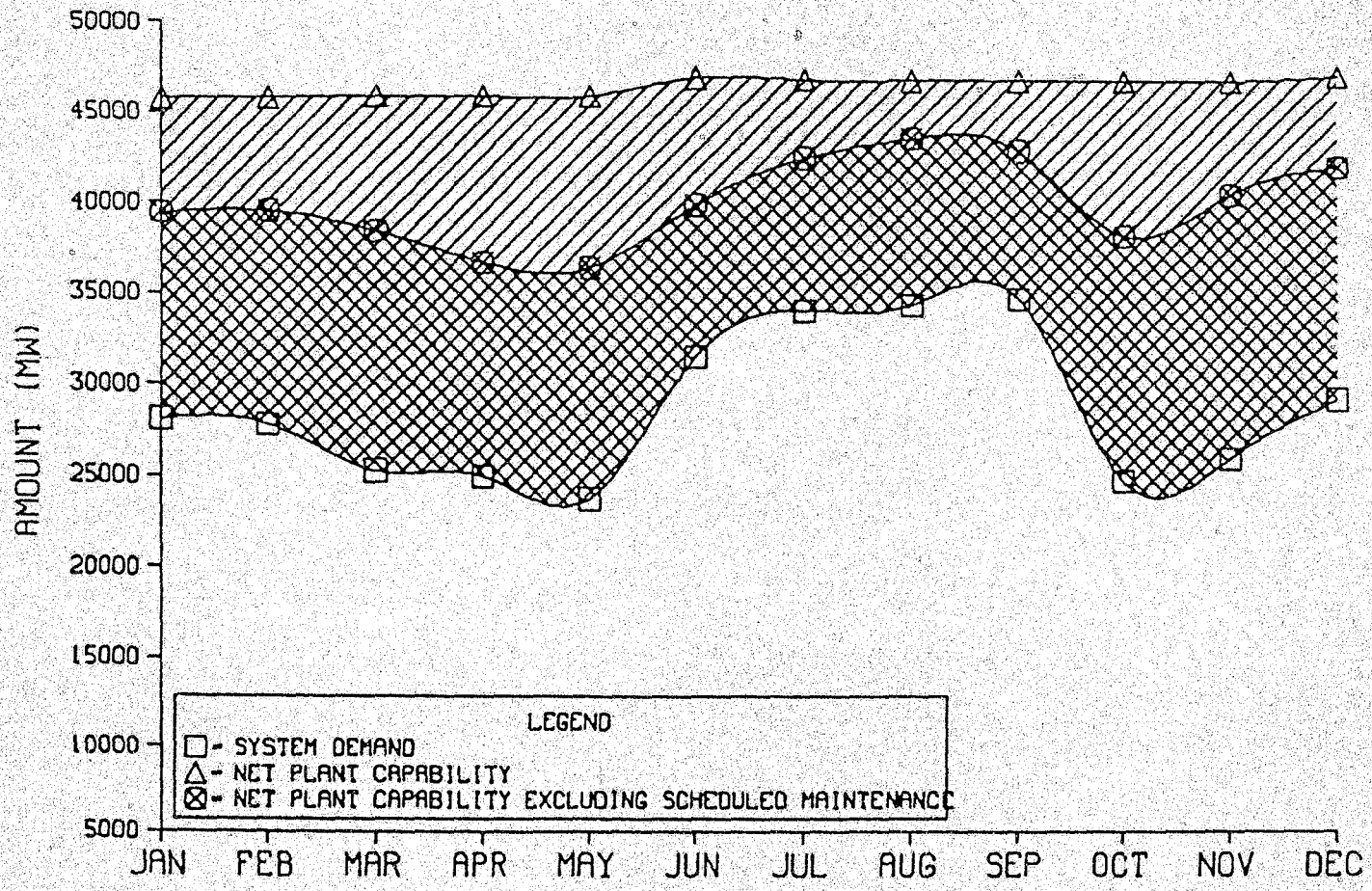


Appendix B
Chart 25

PJM INTERCONNECTION

ANALYSIS OF MONTHLY RESERVE MARGINS

YEAR ENDED DECEMBER 31, 1983

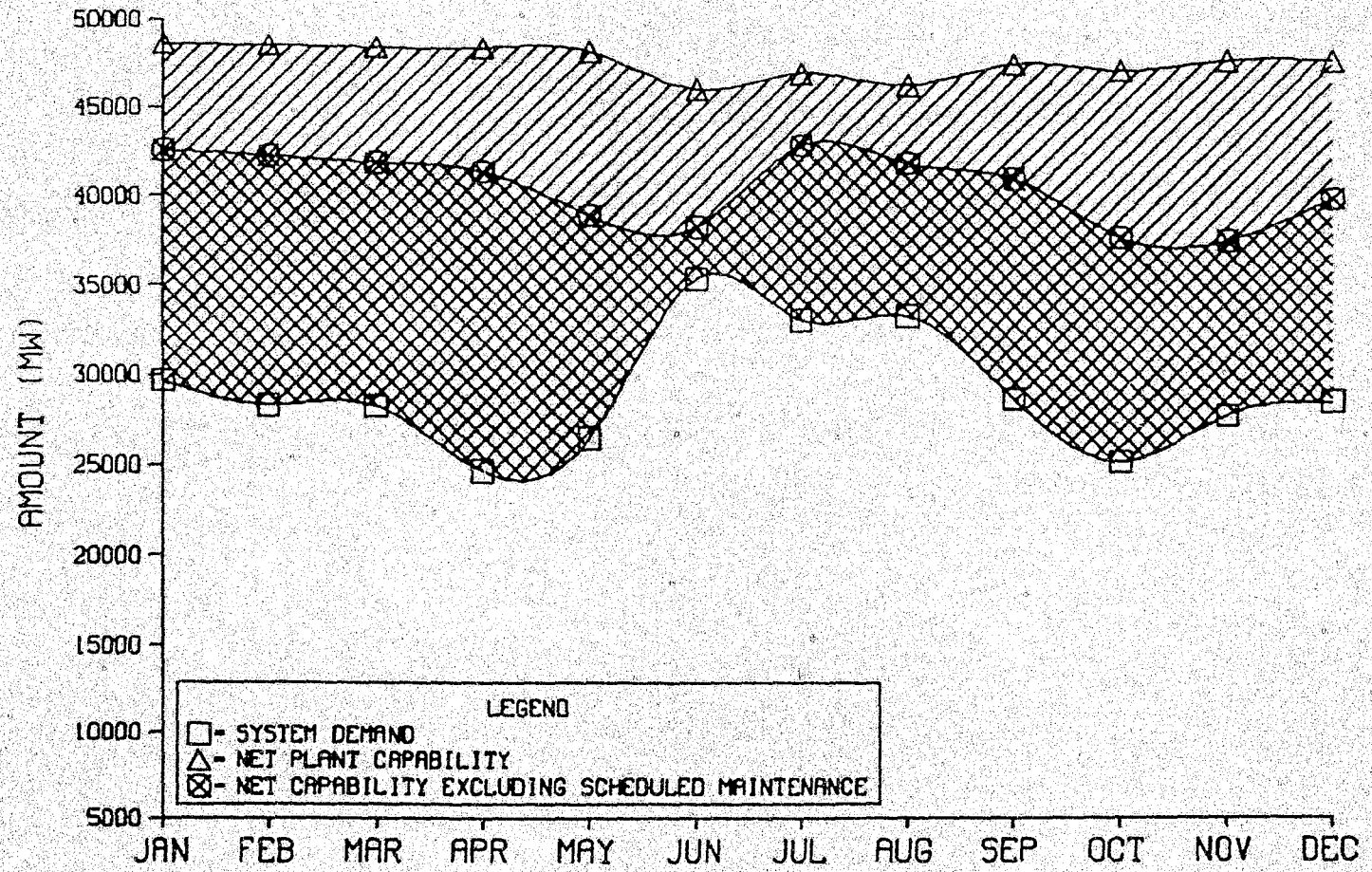


Appendix B
Chart 26

PJM INTERCONNECTION

ANALYSIS OF MONTHLY CAPACITY MARGINS

YEAR ENDED DECEMBER 31, 1984



Appendix B
Chart 27

Before the

Pennsylvania Public Utility Commission

Docket No. R-00860762

PHILADELPHIA ELECTRIC COMPANY

DOCKETED

JAN 23 1986

Testimony and Exhibit

of

JERRY ROTHKOPF

On Behalf of the

Philadelphia Area Industrial Energy User Group

(Allied Corporation acting through its Bendix Process Systems Division
Boeing Vertol Company
E. I. du Pont de Nemours & Co., Inc.
The Budd Company
Liquid Air Corporation of North America
Lukens Steel Company
Nabisco Brands, Inc.
Sun Company, Inc.
Sun Refining and Marketing Company
3M Company)

and

United States Steel Corporation

January 1986

Project 4035

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

Before the

Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Testimony

of

Jeffrey Roberts

On Behalf of the

Philadelphia Area Industrial Energy Users Group

(PAIEUG: Borden, Inc., Chemical Division
Boeing Vertol Company
E. I. du Pont de Nemours & Co., Inc.
The Budd Company
Lukens Steel Company
Nabisco Brands, Inc.
PQ Corporation (f/k/a Burroughs Corporation)
SmithKline Beckman Corporation
Sun Refining and Marketing Company
3M Company)

and

United States Steel Corporation

January 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

Summary of the
Recommendations of Jeffry Pollock

This testimony is being sponsored on behalf of the Philadelphia Area Industrial Energy Users Group (PAIEUG) and U. S. Steel Corporation, and it addresses rate spread and rate design issues. The following is a summary of the specific recommendations:

(1) The four coincident peak (4CP) cost-of-service study filed by Philadelphia Electric Company (PECO) in this Docket (Schedule 1, Page 1) is unacceptable and should be rejected for the reasons cited by my colleague, Dr. Bloom. Specifically:

(a) The weather-sensitive load was significantly understated; and

(b) The Rate HT loads were overstated because the demands related to supplemental energy service and curtailable service were erroneously included in the derivation of the production demand allocation factor (A-1), the same as firm Rate HT demands. This is despite the fact that PECO does not have the same obligation to provide continuous, uninterrupted service. In other words, supplemental and curtailable service is of a lower quality and does not require PECO to construct generation capacity because this service can be curtailed when capacity is unavailable and needed to maintain service to PECO's firm customers.

(2) The adjustments proposed by Dr. Bloom to PECO's 4CP cost-of-service study should be adopted. This study (Schedule 1, Page 2) is a more acceptable basis for determining rate spread and rate design at least for the first year of a phase-in, if adopted by the Commission. Further, the results are more consistent with prior cost studies (Schedule 2).

(3) If a phase-in is adopted, then rate spread issues should be continually reviewed to assure that the rates approved in this Docket would continue to adhere to cost of service. In other words, the phase-in should not provide for automatic recovery because it would maintain (or possibly worsen) the revenue/cost relationships, particularly if conditions that affect the cost-of-service study (e.g., weather) were different than during the test year.

(4) Irrespective of which cost-of-service study is determined to be acceptable, the modified zero fuel method--which has been approved by the Commission in the last three PECO rate cases--should be used to distribute the nonfuel portion of any rate increase approved by the Commission, subject to two constraints:

(a) The relative rate of return of any major customer class should not exceed 140% of the system average rate of return.

(b) The revenue subsidies at approved rates should be no higher than, and preferably less than, the corresponding revenue subsidies at present rates (Schedules 3 through 6).

PECO's rate spread should be categorically rejected because: (1) nonjurisdictional classes would be subsidized by retail classes and (2) some retail classes (e.g., street lighting, SEPTA and AMTRAK) would receive more favorable treatment than others.

(5) The design of Rate HT should be modified (relative to PECO's proposal) as follows:

(a) Most of the increase assigned to Rate HT should be recovered in the capacity charge resulting in a much higher percent increase

than in the energy charges. The demand cost recovered in the tail block energy charge should not be increased. At most, the percent increase in the tail block energy charge should not exceed the percent increase in the first and second block energy charges, when measured relative to the present charges excluding embedded fuel costs (Schedules 7 and 8).

(b) The high voltage discount should be modified to include an explicit recognition of the lower cost to provide service to those Rate HT customers who take service at 66,000 volts and above. This lower cost of service is due to the lower demand and energy losses incurred to provide service at these voltages. Because the present discount only reflects the transformation cost avoided by PECO and not the avoided demand and energy losses, these higher voltage customers should receive an additional discount of at least 1% of the capacity and base energy charges.

(c) The Rate HT Curtailment Rider should not be diminished in value (which would be the result of PECO's proposal to maintain the credit at $2.00 per kW). Instead, the credit should be increased to at least $3.40 (and possibly as high as $3.80) in order to maintain the same relationship in the cost of providing curtailable versus firm electric service. By increasing the credit, the Curtailment HT Rider would be more attractive and provide a more suitable alternative to the Supplemental Energy Rider for those customers who determine that a lower quality of service is both cost-effective, as well as cost-competitive (Schedules 9 and 10).

(6) PECO should be ordered to develop certain cost-of-service and rate design data by delivery voltage within the High Tension class in its next rate case. This should include:

(a) Coincident and noncoincident peak demands.

(b) Energy sales, billing demand and demand subject to the high voltage discount.

(c) The transformation and other distribution costs avoided at higher delivery voltages.

(d) Differences in demand and energy losses.

PHILADELPHIA ELECTRIC COMPANY

before the

Pennsylvania Public Utility Commission

Docket No. R-850152

Testimony of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q WOULD YOU PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE?

A This is set forth in Appendix A to the testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Philadelphia Area Industrial Energy Users Group (PAIEUG) and U. S. Steel Corporation, all of whom are customers of Philadelphia Electric Company (PECO). These companies use substantial amounts of electricity primarily for manufacturing, and they purchase electric service on Rate HT.

Q WHAT ISSUES DO YOU ADDRESS?

A I am testifying on the method of spreading the nonfuel rate increase among the various rate schedules (rate spread) and the design of Rate HT.

A summary of the specific recommendations is incorporated

prior to the main body of testimony.

Q IS DR. MELVIN P. BLOOM ALSO APPEARING ON BEHALF OF THE SAME INTERVENORS LISTED ABOVE?

A Yes. Dr. Bloom is testifying on cost-of-service and rate design issues including:

(1) PECO's 4CP cost-of-service study and, in particular, the derivation of the various demand allocation factors,

(2) The problems with using the Bary curve for rate design, and

(3) The load characteristics of PECO and the load and supply characteristics reserve of the PJM interconnected system.

Q DOES YOUR TESTIMONY ADDRESS REVENUE REQUIREMENT ISSUES?

A No. However, I have used PECO's claimed rate base, rate of return and operating expenses for the test year ending June 30, 1986 so that our presentation would be consistent with the revenue levels proposed by PECO. The use of this information should not be considered as an endorsement of PECO's claimed revenue requirement.

Q HAVE YOU PREPARED ANY EXHIBITS FOR SUBMISSION?

A Yes. I am sponsoring Exhibit JP-1 ( ), consisting of ten schedules.

THE RESULTS OF PECO'S 4CP COST-OF-SERVICE STUDY ARE ERRONEOUS AND, THEREFORE, IT SHOULD NOT BE USED TO DETERMINE THE RATE SPREAD AND RATE DESIGN

Q MR. SUNDERMEIR, ON BEHALF OF PECO, HAS TESTIFIED THAT THE COST OF

SERVICE STUDY PRESENTED IN EXHIBIT WFS-1 UTILIZES ESSENTIALLY THE SAME ALLOCATION TECHNIQUES THAT HAVE BEEN USED IN PRIOR PECO RATE CASES. DO YOU CONCUR?

A Yes. Except for the treatment of the SEPTA and AMTRAK loads as separate customer classes (rather than combined with the high tension class as in the past), the cost-of-service study presented in this Docket is essentially the same as the studies presented by PECO in prior rate cases.

Q ARE THE RESULTS OF PECO'S 4CP COST-OF-SERVICE STUDY IN THIS DOCKET ACCEPTABLE FOR USE IN DETERMINING RATE SPREAD AND RATE DESIGN ISSUES?

A No, they are not. Although PECO has employed the same allocation techniques as in the past, the results should not be used to determine rate spread and rate design in this Docket because, based on Dr. Bloom's analysis, the various demand allocation factors are erroneous. Specifically, Dr. Bloom has identified two problems with the demand allocation factors.

First, the weather-sensitive demands were signficantly understated relative to past cost-of-service studies. This occurred because the summer of 1984--which was used as the starting point for developing the test year demand allocation factors--was significantly cooler than normal as measured by the effective degree hours (EDH) in each of the four summer peak months. I have reviewed Dr. Bloom's analysis and concur with his findings with respect to the

abnormal 1984 summer weather conditions.

Q WHAT WAS THE SECOND PROBLEM WITH THE 4CP DEMAND ALLOCATION FACTORS?

A In deriving the demand allocation factors, PECO used the total coincident demand of each Rate HT customer, irrespective of the quality of service provided. This is an important distinction for the high tension class because not all service is provided on a firm basis. A significant portion of service is provided on a curtailable basis either from the HT Curtailment Rider or the Supplemental Energy provision of the Night Service HT Rider.

Q WHY IS IT IMPORTANT TO DISTINGUISH BETWEEN THE QUALITY OF SERVICE IN DEVELOPING THE DEMAND ALLOCATION FACTORS?

A If the lower quality of service provided to the curtailment and supplemental energy customers is not recognized for costing purposes, but is reflected in the determination of that class's revenues, then the inevitable result would be to understate the class's rate of return. This occurs because, for costing purposes, the demands are assumed to be firm while, for revenue purposes, not all of the demand is priced at the firm rate. Because curtailment and supplemental energy service is priced below the corresponding price for firm service (in recognition of the lower quality of service), the revenues are below the level which they would otherwise be if the entire class received firm electric service.

In summary, there is a fundamental mismatch between costing

and pricing for the high tension class. In this instance, the high tension class cost of service is overstated relative to the price which high tension customers pay. Although the price reflects the different quality of service provided to the high tension class, the costs allocated to this class do not.

Q HOW SHOULD THIS MISMATCH BE RESOLVED?

A An appropriate resolution would be to completely remove that portion of the high tension class's coincident demand related to curtailment or supplemental energy service. This treatment is appropriate because PECO does not have the same obligation to provide continuous service to curtailment and supplemental energy customers as it has in the case of all other firm customers.

For example, according to the tariff (Electric-Pa. PUC No.26, Page No. 61), supplemental energy "must be completely interruptible on notice of at least one-half hour when, in the sole judgment of the Company, any capacity limitations exist." Based on PECO's response to IR-PAIEUG-1-12, the phrase "capacity limitations" means whenever PECO is required to utilize maximum emergency generation. In other words, when the supply of electricity is limited relative to the demand, the Company will require interruptions. The same provision also applies for curtailment service.

Stated differently, if the capacity which is presently being used by curtailment and supplemental energy customers is required in order to continue service to the utility's firm customers, the

former load can be removed from the system. Thus, PECO does not have the same obligation to provide a continuous supply of power to its curtailment and supplemental energy customers as it has to its firm customers. This being the case, there is no production demand-related cost associated with, or allocable to, curtailment and supplemental energy service.

Q WOULD THIS STILL BE THE CASE EVEN THOUGH, ACCORDING TO ITS OWN PROJECTIONS, PECO WILL EXPERIENCE RESERVE MARGINS IN EXCESS OF ITS PLANNING RESERVE MARGIN?

A Yes. Even assuming that the amount of installed capacity were more than adequate to serve the load at all times, the presence of curtailment and supplemental energy load provides a hedge against: (1) the possibility that sufficient generating capacity may, at times, be unavailable due to a forced or scheduled outage or because the utility has elected not to have this capacity in an operating status; and (2) the uncertainties surrounding the load forecasts--that is, tomorrow's load is never known with certainty. Further, because this capacity can be utilized to provide curtailment and supplemental energy service to the extent that it is not required to maintain firm service, the utility is able to defray more of the fixed costs than would otherwise be the case if this service were not provided.

Thus, curtailment and supplemental energy loads provide two important benefits to all ratepayers. First, in the long run, this

service could offset some of the cost of providing reserve generating capacity requirements, thereby reducing total capacity costs from what they would otherwise be without the presence of curtailment and supplemental energy service. Second, this service helps to defray some of the fixed costs and, therefore, reduces the cost to serve the remaining firm customers.

Q HAVE YOU REVIEWED THE SPECIFIC ADJUSTMENT RECOMMENDED BY DR. BLOOM TO REMOVE THE CURTAILMENT AND SUPPLEMENTAL ENERGY DEMANDS FROM THE HIGH TENSION CLASS COINCIDENT PEAK DEMANDS?

A Yes, I have. I concur with Dr. Bloom's adjustments. (It should be noted that, because the supplemental energy revenues were not reflected in the cost-of-service study, the high tension class rate of return is understated even though the curtailable demands were removed.)

THE PAIEUG ET AL REVISED 4CP COST-OF-SERVICE STUDY SHOULD BE USED TO DETERMINE THE RATE SPREAD AND RATE DESIGN IN THIS DOCKET

Q DO THE TWO ADJUSTMENTS RECOMMENDED BY DR. BLOOM TO THE DEMAND ALLOCATION FACTORS HAVE A SIGNIFICANT IMPACT ON THE COST-OF-SERVICE STUDY RESULTS BASED ON THE 4CP METHOD?

A Yes, they do. Exhibit JP-1 ( ), Schedule 1, is a summary of the cost-of-service study results. Page 1 is based on PECO's cost study, while Page 2 is based on one of the revised cost studies that Dr. Bloom is sponsoring. In this particular study, the weather-sensitive demands were reflective of the EDH's during the

four summer peak days in 1985. As Dr. Bloom demonstrates in his Exhibit MPB-3 ( ), this revised study yields the lowest rate of return for the high tension class relative to the other weather-adjusted cost studies.

For example, under the PAIEUG et al revised 4CP cost-of-service study, the high tension class is equal to the system average rate of return at present rates. Under PECO's cost study, by comparison, this class would have a below-average rate of return. This translates into about a $50 million differential in the high tension class revenue requirements at present rates.

The results are also significantly different for the primary and residential classes. Under the revised study, the primary class rate of return is above the system average at present rates, while under PECO's cost study, it is close to, but below, the system average. Similarly, the residential class rate of return is below (rather than equal to) the system average based on this class's coincident demands which are reflective of more normal summer peak day weather conditions.

As further evidence that Dr. Bloom's adjustments to the demand allocation factors are appropriate, Exhibit JP-1 ( ), Schedule 2, demonstrates that the results of the PAIEUG et al cost study are much more consistent with prior PECO 4CP cost-of-service studies than the current PECO cost study. This consistency is illustrated below:

Comparison of 4CP Cost-of-Service Study Results Between Last Case and This Case Based on PAIEUG et al's Adjustments

Rate Class	Index of Return		
		This Case	
	Last Case*	PAIEUG et al	PECO
High Tension**	116	100	84
Primary	140	117	97
Secondary	140	126	126
Residential	71	84	100
Street Lighting	90	198	197

*PECO proposed rates
**Includes SEPTA and AMTRAK

Further, under PECO's proposed rate spread, the interclass subsidies would be much more substantial based on the revised (1985 EDH) cost study. For example, under the revised study, the high tension class would be providing a $55.7 million subsidy at proposed rates. By contrast, PECO's cost study shows that this class would be subsidized by about $24.7 million. Thus, the results differ by nearly $80 million at proposed rates for the high tension class. There are also significant differences between these two cost studies for other classes as well (e.g., primary, $22 million; residential, $94 million, et cetera).

Q WHAT IMPLICATIONS DO YOUR FINDINGS HAVE RELATIVE TO PECO'S PROPOSED PHASE-IN?

A It has serious implications. PECO's phase-in proposal could remain in effect for up to six years. If the utility opts not to file a base rate case during the pendency of the phase-in, then the proposed rate spread--which is based on PECO's erroneous

cost-of-service study--would be perpetuated despite its obvious inequities. Thus, it would not be appropriate, in my opinion, to develop a permanent rate spread which would remain in effect for possibly up to six years, particularly when the cost-of-service study results are significantly affected by the abnormal summer of 1984 peak day weather conditions.

Q HOW CAN THIS PROBLEM BE RESOLVED IN THE CONTEXT OF A PHASE-IN?

A My recommendation would be that the Commission not allow automatic rate increases if a phase-in plan is adopted. As Mr. Randall Falkenberg (of Kennedy & Associates) testifies (on behalf of PAIEUG), automatic recovery assumes that all factors affecting the revenue requirement and rate spread stay the same. Thus, under an automatic plan, it is possible for a utility to earn excess returns if for example, the required cost of equity decreases, O&M expenses increase by a lesser amount, or if sales volumes increase beyond those expected. Similarly, Dr. Bloom has demonstrated that weather-related factors can significantly affect the demand allocation factors and, thus, the class rates of return in a cost-of-service study. If PECO were to conduct a cost-of-service study for the year 1987 based on 1985 weather conditions, the results would be substantially different from those derived in the test year cost-of-service study filed in this Docket (based on the abnormal 1984 summer peak day weather conditions).

Thus, there could be a significant risk that, by preserving

the rate spread developed in this Docket throughout the pendency of the phase-in could result in a significant worsening of the revenue/cost relationships. Because of the simplistic rate spread and rate design aspect of an automatic recovery program, there is no assurance that the rates in the future would continue to adhere to cost.

Therefore, I recommend that the Commission order PECO to file updated cost-of-service studies if a phase-in plan is adopted. The purpose of these updated studies would be to ensure that the rates continue to reasonably adhere to costs during the pendency of the phase-in. To the extent that these subsequent cost-of-service studies demonstrated that rates were deviating from cost, then the Commission should have the ability to modify the rate spread adopted in this Docket.

COST OF SERVICE SHOULD BE THE PRIMARY BASIS FOR DETERMINING THE RATE SPREAD AND RATE DESIGN

Q WHAT CRITERIA SHOULD BE USED TO DETERMINE BOTH THE RATE SPREAD AND RATE DESIGN?

A Although other factors may be considered, such as gradualism, ease of administration and simplicity, primary emphasis should be placed on the cost of providing service to determine the revenue requirements from each class (rate spread) and from each customer within a class (rate design). The basic reasons for adhering to the cost-of-service principle throughout the revenue allocation and rate design processes are equity, engineering efficiency (cost-minimization),

stability and conservation.

Rates which reflect primarily cost-of-service considerations are equitable because each customer pays what it costs the utility to serve him, no more and no less. If rates are not based on costs, then some customers must pay part of the costs of providing service to other customers, which is inequitable.

With respect to engineering efficiency, when rates are designed so that demand and energy charges are properly reflected in the rate structure, the utility has an incentive to construct the most economical mix of plants, and customers are provided with the proper incentive to minimize their costs, which will in turn minimize the costs to the utility.

When rates are closely tied to cost, the utility's earnings are stabilized because changes in customer use patterns would result in parallel changes in revenues and expenses. Cost-based rates also provide a more stable basis for determining future levels of power costs. If rates are based, instead, on vague social policies, it becomes much more difficult to translate expected utility-wide cost changes into changes in the rates charged to particular customer classes. This added element of uncertainty will lessen the attractiveness of industrial expansion either by new or existing industries.

To the extent that rates do not reflect cost, multi-plant firms will be encouraged to shift production from high energy cost plants to lower energy cost plants in order to remain competitive.

Such a shifting of production would reduce employment and the overall contribution of the manufacturing concern to the state and local economy. This would, in turn, be self-defeating to the presumed beneficiaries of below-cost electric rates.

Finally, by providing balanced price signals against which to make consumption decisions, cost-based rates encourage conservation (of both capacity and energy), which is properly defined as the avoidance of wasteful or inefficient use (and not just less use). If rates are not based on costs, then the choices are distorted.

Q HOW HAS PECO PROPOSED TO ALLOCATE THE INCREASE AMONG THE CUSTOMER CLASSES?

A According to Mr. Williams, the increase was spread among the various rate classifications in proportion to base revenues, except (1) where the index of return would exceed 140%, (2) for SEPTA and AMTRAK (whose rates of return were set at the system average), and (3) for those classes whose index of return would increase relative to present rates. This resulted in the rate spread shown in Exhibit JP-1 ( ), Schedules 3 and 4.

In Schedule 3, the proposed net revenue increase is measured relative to base revenues by rate schedule.

Schedule 4, Page 1, shows the spread of the increase (before fuel savings) measured relative to nonfuel revenue. The latter is derived in Schedule 4, Page 2. This is, of course, a more meaningful comparison of the relative impact of a nonfuel-related increase.

PECO's proposed rate spread would result in above-average percent increases to Rate PD and Rate HT and below-average percent increases to the remaining rate schedules.

Q IS THIS A DIFFERENT RATE SPREAD APPROACH THAN PECO PROPOSED IN ITS LAST SEVERAL RATE CASES?

A Yes, it is. In the last three PECO rate proceedings, PECO proposed (and the Commission approved) to spread the increase relative to a proportion of revenue from each rate classification after all fuel revenue was removed. This approach was modified for those customer classes whose rates of return were either: (1) less than the system average or (2) greater than 130% to 140% of the system average rate of return. The stated objectives behind this approach were:

(1) To narrow the gap between class rates of return and the system average rate of return,

(2) To avoid any disruptive changes in the pattern of rates which would unduly affect any one customer class,

(3) To recognize the fact that energy costs do not contribute to the present need for additional revenue, and

(4) To be consistent with the methodology approved by the Commission.

In approving PECO's rate spread methodology, the Commission stated that:

> "Increased fuel costs are recovered in the ECR, and are not part of the base revenue increase at issue in this proceeding. Fuel revenue therefore should not be considered in allocating a rate increase related solely to nonfuel costs. The

Company's proposal accomplishes this result by removing all fuel revenue before allocating the increase." (PECO St. 10B, Page 3; Opinion and Order, Page 138, in Docket No. R-842590)

Thus, PECO's rate spread proposal in this Docket differs substantially from its proposals in prior rate cases and Commission precedent.

Q WOULD PECO'S PROPOSED RATE SPREAD MOVE THE RATES OF EACH CLASS SYSTEMATICALLY CLOSER TO COST?

A No, based on the PAIEUG et al revised 4CP cost-of-service study, the rates would not move closer to cost in most instances, as demonstrated in Exhibit JP-1 ( ), Schedule 1, Page 2. The lack of movement toward cost under the revised cost study is illustrated below:

PAIEUG et al Revised Cost-of-Service Study Results at Present and Proposed Rates

	Index of Return		Interclass Subsidy		
Rate Class	Present Rates	Proposed Rates	Present Rates ($Millions)	Proposed Rates ($Millions)	Movement Toward Cost
High Tension	99	109	$ -3.6	$ 55.7	No
Primary	116	113	11.4	18.2	No
Secondary	126	115	32.1	37.8	No
Residential	84	86	-58.0	-100.4	No
Street Lighting	198	106	9.4	1.2	Yes
SEPTA	119	97	1.3	-0.4	Yes
AMTRAK	144	99	3.8	-0.1	Yes
Other	122	66	3.6	-12.0	No

Q WHAT ARE THE INDEX OF RETURN AND THE INTERCLASS SUBSIDY?

A The index of return and the interclass subsidy are two other ways to measure the results of a cost-of-service study, besides rate of return.

The index of return is a measure of the relative rates of return of each class vis-a-vis the total Company rate of return. An index below 100 indicates that a class's revenues are not sufficient to recover its cost of service, while an index above 100 indicates that a class is being overcharged relative to cost. Mathematically, the index is derived by dividing each class's rate of return by the total Company rate of return.

The interclass subsidy is an annual statistic which measures the difference between the revenues required from each class and the revenues actually recovered. A negative amount indicates that a class is being subsidized each year (revenues are below cost), while a positive amount indicates that a class is providing a subsidy each year (revenues are above cost).

Q ARE THERE ANY OTHER PROBLEMS WITH PECO'S PROPOSED RATE SPREAD?

A Yes, there are. First, the nonjurisdictional class (other utilities) would be providing a substantially below-average rate of return. Unless this return is brought up to the system average, the retail classes would be subsidizing PECO's nonjurisdictional sales.

Second, it is obvious that some classes are receiving more favorable treatment than others. This is evident from the fact that, under PECO's rate spread, the street lighting, SEPTA and

AMTRAK rates would be moved significantly closer to cost, while just the opposite would occur for other classes. If PECO's objective is to move the rates of return closer to the average, then it should do so for all classes and not pick and choose to accomplish some arbitrary end result.

Q WHICH MEASURE--THE INDEX OF RETURN OR THE INTERCLASS SUBSIDY--IS THE MORE APPROPRIATE BASIS FOR DETERMINING WHETHER THE RATES WOULD BE MOVED CLOSER TO COST?

A The interclass subsidy is the more appropriate basis to determine whether rates are being moved closer to cost. Under some circumstances, the index of profitability could move closer to 100, but the interclass subsidy could either remain the same or increase.

For example, based on the PAIEUG et al revised cost-of-service study, the index of return from the secondary class would be 126 at present rates and 116 at proposed rates. However, the annual revenue subsidies--the difference between actual revenues and required revenues--would be $32,095,000 at present rates and $37,841,000 at proposed rates per year. This represents an increase of $5,700,000. Since the dollar subsidy would increase, this would not indicate a movement toward cost despite the fact that the relative rate of return would be closer to 100 (unity).

Thus, although the indexes of return create the appearance that rates are generally being moved closer to cost, this movement may only be an illusion if the interclass subsidies actually

increase.

Q WOULD YOUR ANSWER BE THE SAME BASED ON THE RESULTS OF PECO'S COST-OF-SERVICE STUDIES?

A Yes, it would. Even based on its (flawed) study, PECO's proposed rate spread would not systematically move all customer classes toward cost, not to mention that the rates would move farther from cost for three of the major classes--primary, secondary and residential. In fact, it is obvious that some classes (i.e., street lighting, SEPTA and AMTRAK) would be receiving more favorable treatment because their rates would move much closer to cost than would the other classes.

Q HAVE YOU DEVELOPED AN ALTERNATIVE INTERCLASS REVENUE ALLOCATION WHICH WOULD BETTER ACHIEVE THE OBJECTIVE OF MOVING ALL CLASSES SYSTEMATICALLY CLOSER TO COST?

A Yes, I have. This alternative recommendation is shown in Exhibit JP-1 ( ), Schedule 5.

The approach was similar to the rate spread methodology approved by the Commission in prior PECO rate cases. Specifically, I am recommending that the nonfuel increase be spread among the various rate schedules relative to nonfuel revenues provided that (1) the interclass revenue subsidy is either maintained or reduced relative to the subsidy at present rates, and (2) the index of return does not exceed 140% of the system average return. By at

least maintaining the subsidies for all classes, my proposed rate spread would prevent some classes from receiving more favorable treatment at the expense of others.

Q WOULD THE RATES MOVE CLOSER TO COST UNDER YOUR RECOMMENDED INTER-CLASS REVENUE ALLOCATION?

A In general, the rates would not be moved closer to cost because the interclass subsidies would not change. However, the recommended spread would be preferable (in terms of adhering to the cost-of-service study results) to PECO's proposal as shown in Exhibit JP-1 ( ), Schedule 6, and as demonstrated below:

PAIEUG et al's Revised Cost-of-Service Study Results at Proposed and Recommended Rates

	Index of Return		Interclass Subsidy	
Rate Class	Proposed Rates	Recommended Rates	Proposed Rates ($Millions)	Recommended Rates ($Millions)
High Tension	109	100	$ 55.7	$ -
Primary	113	108	18.2	11.4
Secondary	115	113	37.8	32.1
Residential	86	92	-100.4	-56.1
Street Lighting	106	140	1.2	7.5
SEPTA	97	109	-0.4	1.3
AMTRAK	99	122	-0.1	3.8
Other	66	100	-12.0	-

Q IS NOT YOUR RECOMMENDED RATE SPREAD INAPPROPRIATE BASED ON THE MAGNITUDE OF THE RATE INCREASE WHICH PECO IS SEEKING IN THIS DOCKET?

A No, it is not. Although the magnitude of the total increase is quite large relative to prior PECO rate increases, this would be

equally true for all rate classes assuming that the entire increase is awarded in full at the end of this Docket. However, it is for this very reason that PECO has proposed a phase-in. Because the proposed phase-in would provide for substantial rate moderation, there is no valid reason not to spread the increase in a manner which would more closely adhere to the cost-of-service study results. The recommended rate spread would better accomplish this objective than would PECO's proposal, while, at the same time, not result in an overly-abrupt increase for any rate classification.

Q IF THE COMMISSION WERE TO AWARD A SMALLER INCREASE THAN PECO HAS REQUESTED, HOW SHOULD THIS SMALLER INCREASE BE SPREAD AMONG THE VARIOUS RATE CLASSIFICATIONS?

A My recommendation would be to follow the same procedure as described earlier. Specifically, the increase should be spread on an equal percent basis relative to nonfuel revenues subject to the three constraints as follows:

(1) The interclass subsidies should be maintained (or possibly reduced), and

(2) The index of return should not exceed 140% for any major class.

Further, these constraints should be applied in the context of a revised cost-of-service study which takes into account all of the Commission-approved adjustments to rate base, revenues and expenses.

PECO'S PROPOSED DESIGN
OF RATE HT SHOULD BE MODIFIED

Q WHAT MODIFICATIONS ARE YOU RECOMMENDING BE MADE TO PECO'S PROPOSED RATE HT?

A I am recommending three changes in PECO's proposed design of Rate HT. They include:

(1) A lower tail block energy charge (3.18¢ based on PECO's proposed rate spread),

(2) Higher voltage discounts for service delivered at 66 kV and higher (equal to 1% of the base capacity and energy charges), and

(3) An increase in the Rate HT curtailment credit (to at least $3.40 based on PECO's proposed rate spread and rate design).

The above recommendations are based on a continued application of cost-of-service principles in the rate design process, and at least two of the recommendations are supported by precedent.

Q TURNING FIRST TO THE RATE HT TAIL BLOCK ENERGY CHARGE, WHAT IS THE BASIS FOR RECOMMENDING A LOWER CHARGE THAN PECO HAS PROPOSED?

A Applying the same cost-of-service principles in the rate design process as were applied in the cost allocation process, it follows that the demand charges should basically recover demand-related costs, while the energy charges should basically recover energy-related costs.

Q DOES THE PRESENT TAIL BLOCK ENERGY CHARGE RECOVER ONLY ENERGY-RELATED COSTS?

A No, it does not. Referring to Exhibit JP-1 ( ), Schedule 7, Column 1, the present tail block energy charge was designed to recover 0.5725¢ per kWh of demand costs.

Q HOW MUCH DEMAND COSTS WOULD BE RECOVERED IN THE PROPOSED TAIL BLOCK ENERGY CHARGE?

A Schedule 7, Column 2, shows that the demand cost recovery would be 1.1460¢ per kWh. This is more than 100% higher than the demand cost recovery at present rates. By contrast, the nonfuel energy-related component would increase by only 53%.

Q ISN'T THIS SIMPLY A REFLECTION THAT DEMAND-RELATED COSTS ARE INCREASING FASTER THAN NONFUEL ENERGY-RELATED COSTS?

A No, not entirely. PECO is only proposing to increase the capacity charge by about 76%. Thus, the proposed increase in the demand cost recovery within the tail energy block would substantially exceed the increase in demand-related costs. The result would be that more demand-related costs would be recovered in the tail energy block.

Q WHAT ARE THE CONSEQUENCES OF INCREASING THE RECOVERY OF DEMAND COSTS THROUGH AN ENERGY CHARGE?

A Increasing the recovery of demand-related costs in the tail block energy charge could exacerbate the problem of revenue and income instability. For example, if the level of kilowatthour sales

decreases (as often happens during an economic downturn), the utility's revenues will drop more than its costs because the demand costs will still be incurred since they are fixed. On the other hand, if the energy charge recovers basically energy-related costs, then the decline in revenues should parallel the corresponding decline in costs (because the energy charges basically recover only those costs which do, in fact, vary with the number of kilowatt-hours sold).

Q ISN'T PECO'S PROPOSED TAIL BLOCK ENERGY CHARGE BASED ON A DETAILED COST ANALYSIS?

A Yes, it is. However, as Dr. Bloom testifies, the cost analysis used for rate design purposes (i.e., the Bary curve) is not consistent with the demand cost allocation method (i.e., the 4CP method) which was used to determine class revenue requirements. (A more detailed description of this inconsistency appears in Dr. Bloom's testimony.)

Q WHAT IS YOUR RECOMMENDATION?

A My recommendation would be to maintain the level of demand cost recovery which is reflected in the present tail block energy charge (of .5725¢ per kWh). This would result in a charge of 3.18¢ per kWh. Because this is lower than the 3.75¢ charge which PECO is proposing, the revenue shortfall should be recovered through the capacity charge. This would result in a capacity charge of $10.40

per kW, as shown in Exhibit JP-1 ( ), Schedule 8, Column 1, based on PECO's proposed rate spread. If PAIEUG et al's recommended rate spread is adopted, then the capacity charge should be $10.19, as shown in Column 2. Alternatively, the percent increase in the tail block energy should be no higher than the percent increase in the first and second energy blocks, excluding embedded fuel cost. This alternative is shown in Column 3.

The rate values shown in Schedule 8 assume that PECO is awarded the full increase which it is proposing (before the phase-in) and that the recommended changes in the high voltage discount and curtailable credit are adopted.

Q WHAT IS THE BASIS FOR YOUR RECOMMENDED CUSTOMER CHARGE?

A The $281.50 customer charge reflects the customer-related cost of service of the high tension class.

Q TURNING TO THE HIGH VOLTAGE DISCOUNT, WHAT IS THE NATURE OF THE CHANGE WHICH YOU ARE RECOMMENDING?

A My recommendation is to increase the high voltage discount so that Rate HT customers taking service at 66,000 volts and higher receive an additional credit of 1% of the base capacity and energy charges. The basis for the recommendation is to better reflect the cost differential of providing service at the various delivery voltages at which service is provided under Rate HT. These cost differences would arise because: (1) PECO incurs lower demand and energy losses

to provide service at higher delivery voltages (66,000 volts, 133,000 volts, et cetera) and (2) it need not install lower voltage facilities (i.e., 33,000 volts, 13,200 volts, et cetera) to serve higher voltage Rate HT customers.

The present structure of Rate HT only recognizes the transformation costs which PECO avoids by providing service at the higher delivery voltages. It does not reflect the differences in demand and energy losses, and it may not take into account costs other than transformation which PECO avoids in providing service at higher delivery voltages. Thus, ignoring the existing and proposed high voltage discounts, two customers having identical billing demands and kilowatthour consumption would pay the same for electricity even though they may be served at different high tension delivery voltages.

Q CAN YOU CITE ANY OTHER EXAMPLES WHERE SUCH ADDITIONAL VOLTAGE DISCOUNTS ARE IN PLACE?

A Yes. Two examples that come to mind are Pennsylvania Power Company and Pennsylvania Power & Light Company.

Pennsylvania Power Company's General Service-Transmission Rate Schedule (GT) is the equivalent of PECO's Rate HT. Service under Rate Schedule GT is provided at nominal transmission voltages of 23,000 volts or above. However, the stated capacity and energy charges are clearly applicable to service which is provided at 23,000 volts. An additional discount of 3% is applied to the

capacity and energy charge when service is provided at 69,000 volts, while a 5% discount is applied when service is provided at 138,000 volts.

In the case of Pennsylvania Power & Light Company, there are two separate tariff schedules for high tension customers, LP-4 and LP-5. Rate LP-5 is applicable to service provided at 66,000 volts or higher. Rate LP-4 is applicable at lower high tension delivery voltages (e.g., 13,200 volts, 33,000 volts, et cetera). Comparing the cost of electricity between the two rates, it is apparent that the higher voltage customers served on Rate LP-5 are paying less than Rate LP-4 customers of a comparable size and load factor.

Thus, the incorporation of an additional 1% discount on the capacity and energy charges for 66,000-volt and higher service is conservative and should be regarded as an initial step. Because PECO has not quantified the demand and energy loss differences within Rate HT and because there may be additional costs avoided (other than transformation costs), the utility should be ordered to develop certain additional cost-of-service and rate design data in its next rate case including:

(a) Coincident and noncoincident peak demands.

(b) Energy sales, billing demand and demand subject to the high voltage discount.

(c) The avoided transformation and other distribution costs at the higher delivery voltages.

(d) The differences in both demand and energy losses.

The above information should make it possible to refine the determination of the demand and energy cost differentials by delivery voltage within the high tension class.

Q WHAT IS THE BASIS FOR YOUR RECOMMENDATION THAT THE RATE HT CURTAILMENT CREDIT BE INCREASED TO AT LEAST $3.40?

A This recommendation is designed to maintain the relationship between firm and curtailable service which presently exists. Because PECO is proposing no increase in the $2.00 per kW credit, there would be a significant reduction in the relative cost differential, as shown in Exhibit JP-1 ( ), Schedule 9, Page 1.

For example, at present rates, the $2.00 per kW credit is about 15% of the effective Rate HT demand charge above 300 hours' use. At proposed rates, the effective demand credit would be only 9%. (The effective demand charge is derived on Page 2, and it is equal to the sum of the capacity charge and the demand costs recovered in the first two energy blocks. Page 3 demonstrates that, above 300 hours' use, Rate HT is equivalent to a flat rate having a capacity charge of $13.515 per kW and an energy charge of $.0376 per kWh.)

Comparing the monthly nonfuel cost for a hypothetical customer having a 10,000-kW maximum registered demand operating at a 90% load factor (Schedule 9, Page 1), the present credit for curtailable service would be 4.6%. This would be reduced to 2.7% at proposed rates. Thus, with no increase in the curtailment credit,

curtailable service would become even less attractive than is presently the case. It should be noted that, when the curtailment credit was first implemented, the effective demand credit was 20%.

Q WHAT CURTAILMENT CREDIT WOULD BE NECESSARY TO MAINTAIN THE EXISTING RELATIONSHIP BETWEEN CURTAILABLE AND FIRM SERVICE?

A Based on PECO's proposed rate spread and rate design, a credit of at least $3.40 per kW would maintain the cost differential between curtailable and firm service, as shown in Exhibit JP-1 ( ), Schedule 10, Column 1. To the extent that either the rate spread or rate design is altered, then the amount of the curtailment credit should also be revised to maintain a consistent relationship, as shown in Columns 2 and 3 of Schedule 10.

Q ARE THERE ANY EXAMPLES WHICH SUPPORT YOUR RECOMMENDATION TO INCREASE THE CURTAILMENT CREDIT?

A Yes. Pennsylvania Power & Light recently implemented Rate Schedule IS-2, which is characterized as a High Load Factor--Interruptible Service Schedule. This rate is for large general service customers who would otherwise take firm electric service on Rate Schedule LP-5. Assuming a customer having a 10,000-kW demand, operating at a 90% load factor and with a firm capacity requirement of 5,500 kW, the cost differential (excluding embedded fuel) would be about 7%. This is much higher than the effective curtailable credit provided by PECO at present rates. Further, the terms and conditions of

PP&L's rate are similar to those in PECO's HT Curtailment Rider.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and am employed by Drazen-Brubaker & Associates, Inc., utility rate and economic consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I am a graduate of Washington University. I hold the degrees of Bachelor of Science in Electrical Engineering and Master of Business Administration. At various times prior to graduation, I worked for the McDonnell Douglas Corporation in the Corporate Planning Department; Sachs Electric Company; and L. K. Comstock & Company. While at McDonnell Douglas, I analyzed the direct operating cost of commercial aircraft. Upon graduation, in June, 1975, I joined the firm of Drazen-Brubaker & Associates, Inc. My work consists of preparation of financial and economic studies relating to electric and gas utilities, including revenue requirements, cost-of-service studies, rate design, and contract analysis.

I have testified before the regulatory commissions of Alabama, Delaware, Florida, Georgia, Illinois, Iowa, Louisiana,

Minnesota, Missouri, Montana, New Jersey, New Mexico, Ohio, Pennsylvania, Texas and Washington. I have also appeared before the Board of Public Utilities of Kansas City, Kansas, and before the Bonneville Power Administration.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and has assumed the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. In the last five years, our firm has participated in more than 700 rate cases in forty states and Canada.

The firm provides consulting services in the field of public utility regulation to many clients, including large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. In addition, we have also prepared depreciation and feasibility studies relating to utility service. In all these cases, it was necessary to analyze the utility's operating and financial records, including property records, depreciation studies, revenues, expenses and taxes. We also assist in the negotiation of contracts for utility service for large users.

In general, we are engaged in regulatory consulting, economic studies and contract negotiation.

Before the

Pennsylvania Public Utility Commission

Docket No. R-850720

PHILADELPHIA ELECTRIC COMPANY

Direct Testimony

of

Jeffrey D. Kopp

On Behalf of the

Philadelphia Area Industrial Energy Users Group

(United Corporations, Others, Dynamon,
Boeing Vertol Company,
B. F. Diehl, Inc.,
The Budd Company,
Liquid Air Corporation of North America,
Lukens Steel Company,
Nabisco Brands, Inc.,
SPS (a Burroughs Company),
Smith Kline Beckman Corporation,
Sun Refining and Marketing Company,
3M Company)

and

United States Steel Corporation

January 1986

Project 4085

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

PHILADELPHIA ELECTRIC COMPANY

Summary of PECO's Cost-of-Service Study Results
at Present and Proposed Rates
Four Coincident Peak Method
Year Ending June 30, 1986

Line	Customer Class	Rate of Return		Index of Return		Interclass Subsidy	
		Present Rates (1)	Proposed Rates (2)	Present Rates (3)	Proposed Rates (4)	Present Rates (000) (5)	Proposed Rates (000) (6)
1	High Tension	5.37%	12.23%	84	96	$(53,079)	$(24,632)
2	Primary	6.21	12.40	97	98	(2,111)	(3,704)
3	Secondary	8.07	14.70	126	116	32,947	39,194
	Residential:						
4	Heating	7.39	14.69	116	116	6,463	12,751
5	Regular	6.14	12.15	96	96	(11,183)	(24,495)
6	Rate OP	21.95	30.97	344	244	5,114	6,006
7	Total Res.	6.39	12.59	100	99	394	(5,738)
	Street Lighting:						
8	Rate SLP	11.12	12.31	174	97	2,936	(242)
9	Rate SLS	13.15	13.70	206	108	5,541	822
10	All Other	18.95	20.51	297	161	866	539
11	Total St. Ltg.	12.58	13.44	197	106	9,343	1,119
12	Other Utilities	9.55	9.55	149	75	5,830	(5,818)
13	Interdepartmental	11.16	11.16	175	88	1,307	(421)
14	SEPTA	7.86	12.70	123	100	1,522	0
15	AMTRAK	9.23	12.70	144	100	3,847	0
16	Total Company	6.39%	12.70%	100	100	$ -	$ -

PHILADELPHIA ELECTRIC COMPANY

Summary of PAIEUG et al Revised Cost-of-Service Study Results
at Present and Proposed Rates
Four Coincident Peak Method
1985 EDH Study
Year Ending June 30, 1986

Line	Customer Class	Rate of Return		Index of Return		Interclass Subsidy	
		Present Rates	Proposed Rates	Present Rates	Proposed Rates	Present Rates (000)	Proposed Rates (000)
		(1)	(2)	(3)	(4)	(5)	(6)
1	High Tension	6.31%	13.88%	99	109	$(3,623)	$ 55,678
2	Primary	7.44	14.38	116	113	11,377	18,161
3	Secondary	8.02	14.63	126	115	32,095	37,841
	Residential:						
4	Heating	5.94	12.25	93	96	(3,352)	(3,346)
5	Regular	5.18	10.62	81	84	(59,750)	(103,109)
6	Rate OP	22.31	31.47	349	248	5,160	6,081
7	Total Res.	5.38	10.95	84	86	(57,942)	(100,374)
	Street Lighting:						
8	Rate SLP	11.20	12.39	175	98	2,965	(191)
9	Rate SLS	13.18	13.74	206	108	5,555	849
10	All Other	19.14	20.72	300	163	873	549
11	Total St. Ltg.	12.64	13.50	198	106	9,392	1,207
12	Other Utilities	7.31	7.31	114	58	2,044	(11,981)
13	Interdepartmental	12.68	12.68	198	100	1,562	(6)
14	SEPTA	7.59	12.32	119	97	1,276	(402)
15	AMTRAK	9.17	12.61	144	99	3,817	(122)
16	Total Company	6.39%	12.70%	100	100	$ -	$ -

PHILADELPHIA ELECTRIC COMPANY

Comparison of Cost-of-Service Study Results
Four Coincident Peak Method

Line	Rate Class	Last Case* (R-842590) (1)	This Case (R-85012) PECO (2)	This Case (R-85012) PAIEUG et al (3)
1	Test Year: Costs	Dec. 1984	- - - June, 1986 - - -	
2	Alloc. Factors	1982	1984	
	Index of Return			
3	High Tension**	116	86	100
4	Primary	140	97	116
5	Secondary	140	126	126
6	Residential	71	100	84
7	Street Lighting	90	197	198
	Source:	PAIEUG Exhibit 1, Schedule 3	WFS-1, Pages 6 and 6a	JP-1, Schedule 1, Page 2

*At PECO's proposed rates

**Includes SEPTA and AMTRAK

PHILADELPHIA ELECTRIC COMPANY

Distribution of Proposed Net Revenue Increase
Relative to Present Base Revenue
Year Ending June 30, 1986

Line	Rate Schedule	Present Base Revenue (000) (1)	Net Revenue Increase Amount (000) (2)	Percent (3)	Index (4)
1	R	$ 739,467	$219,206	29.6%	105
2	RH	127,424	33,003	25.9	92
3	OP	25,989	0	0.0	0
4	POL	1,527	0	0.0	0
5	GS	344,838	102,204	29.6	105
6	PD	191,010	56,630	29.6	105
7	HT	860,983	255,086	29.6	105
8	EPA	31,683	1,471	4.6	16
9	EPS	20,100	2,988	14.9	53
10	SLP	14,993	0	0.0	0
11	SLS	18,129	0	0.0	0
12	TL	3,486	0	0.0	0
13	BLI	7	2	28.6	101
14	TRR	306	89	29.1	103
15	Subtotal	$2,379,942	$670,679	28.2%	100
16	Other Elec. Operations	122,051	11,081	9.1	32
17	Total Company	$2,501,993	$681,760	27.2%	-

PHILADELPHIA ELECTRIC COMPANY

Distribution of Proposed Nonfuel Revenue Increase
Relative to Present Nonfuel Revenue
Year Ending June 30, 1986

Line	Rate Schedule	Present Nonfuel Revenue* (000) (1)	Proposed Nonfuel Revenue Increase Amount (000) (2)	Percent (3)	Index (4)
1	R	$ 553,553	$267,733	48.4%	87
2	RH	83,049	44,585	53.7	97
3	OP	14,672	2,954	20.1	36
4	POL	1,288	62	4.8	9
5	GS	246,883	127,772	51.8	93
6	PD	126,575	73,449	58.0	105
7	HT	495,926	350,372	70.6	127
8	EPA	19,276	4,709	24.4	44
9	EPS	12,380	5,003	40.4	73
10	SLP	11,998	782	6.5	12
11	SLS	16,380	457	2.8	5
12	TL	2,541	247	9.7	18
13	BLI	5	2	47.3	85
14	TRR	306	89	29.1	52
15	Subtotal	$1,584,832	$878,216	55.4%	100
16	Other Elec. Operations	107,964	14,758	13.7	-
17	Total Company	$1,692,796	$892,974	52.8%	-

*Page 2 of 2

PHILADELPHIA ELECTRIC COMPANY

Derivation of Nonfuel Revenue at Present Rates
Year Ending June 30, 1986

Line	Rate Schedule	Energy Sold (MWh) (1)	Present Base Revenue (000) (2)	Embedded Energy Costs* (000) (3)	Present Nonfuel Revenue (000) (4)
1	R	6,465,900	$ 739,467	$185,914	$ 553,553
2	RH	1,543,300	127,424	44,375	83,049
3	OP	393,600	25,989	11,317	14,672
4	POL	8,320	1,527	239	1,288
5	GS	3,406,780	344,838	97,955	246,883
6	PD	2,241,000	191,010	64,435	126,575
7	HT	12,696,300	860,983	365,057	495,926
8	EPA	431,500	31,683	12,407	19,276
9	EPS	268,500	20,100	7,720	12,380
10	SLP	104,148	14,993	2,995	11,998
11	SLS	60,840	18,129	1,749	16,380
12	TL	32,880	3,486	945	2,541
13	BLI	62	7	2	5
14	TRR	0	306	0	306
15	Subtotal	27,653,130	$2,379,942	$795,110	$1,584,832
16	Other Elec. Operations	489,932	122,051	14,087	107,964
17	Total Company	28,143,062	$2,501,993	$809,197	$1,692,796

*Column (1) x 2.8753¢/kWh

PHILADELPHIA ELECTRIC COMPANY

PAIEUG et al Recommended
Distribution of Proposed Nonfuel Revenue Increase
Relative to Present Nonfuel Revenue
Year Ending June 30, 1986

Line	Rate Schedule	Present Nonfuel Revenue (000) (1)	Recommended Nonfuel Revenue Increase Amount (000) (2)	Percent (3)	Index (4)
1	R	$ 553,553	$310,723	56.1%	103
2	RH	83,049	45,639	55.0	101
3	OP	14,672	2,007	13.7	25
4	POL	1,288	62	4.8	9
5	GS	246,883	121,776	49.3	90
6	PD	126,575	66,957	52.9	97
7	HT	495,926	295,796	59.6	109
8	EPA	19,276	8,648	44.9	82
9	EPS	12,380	6,681	54.0	99
10	SLP	11,998	3,516	29.3	54
11	SLS	16,380	4,083	24.9	46
12	TL	2,541	247	9.7	18
13	BLI	5	2	38.3	70
14	TRR	306	89	29.1	53
15	Subtotal	$1,584,832	$866,228	54.7%	100
16	Other Elec. Operations	107,964	26,745	24.8	-
17	Total Company	$1,692,796	$892,973	52.8%	-

PHILADELPHIA ELECTRIC COMPANY

Summary of PAIEUG et al Revised Cost-of-Service Study Results
at Present, Proposed and Recommended Rates
Four Coincident Peak Method
1985 EDH Study
Year Ending June 30, 1986

Line	Customer Class	Rate of Return			Index of Return			Interclass Subsidy		
		Present Rates (1)	Proposed Rates (2)	Recommended Rates (3)	Present Rates (4)	Proposed Rates (5)	Recommended Rates (6)	Present Rates (000) (7)	Proposed Rates (000) (8)	Recommended Rates (000) (9)
1	High Tension	6.31%	13.88%	12.70%	99	109	100	$(3,623)	$ 55,678	$(16)
2	Primary	7.44	14.38	13.75	116	113	108	11,377	18,161	11,377
3	Secondary	8.02	14.63	14.33	126	115	113	32,095	37,841	32,095
	Residential:									
4	Heating	5.94	12.25	12.25	93	96	96	(3,352)	(3,346)	(3,352)
5	Regular	5.18	10.62	11.50	81	84	91	(59,750)	(103,109)	(57,924)
6	Rate OP	22.31	31.47	28.62	349	248	225	5,160	6,081	5,160
7	Total Res.	5.38	10.95	11.69	84	86	92	(57,942)	(100,374)	(56,116)
	Street Lighting:									
8	Rate SLP	11.20	12.39	17.51	175	98	131	2,965	(191)	2,389
9	Rate SLS	13.18	13.74	19.49	206	108	143	5,555	849	4,475
10	All Other	19.14	20.72	25.45	300	163	181	873	549	703
11	Total St. Ltg.	12.64	13.50	18.95	198	106	140	9,392	1,207	7,567
12	Other Utilities	7.31	7.31	12.70	114	58	100	2,044	(11,981)	0
13	Interdepartmental	12.68	12.68	12.70	198	100	100	1,562	(6)	0
14	SEPTA	7.59	12.32	13.91	119	97	109	1,276	(402)	1,276
15	AMTRAK	9.17	12.61	15.49	144	99	122	3,817	(122)	3,817
16	Total Company	6.39%	12.70%	12.70%	100	100	100	$ -	$ -	$ -

PHILADELPHIA ELECTRIC COMPANY

Analysis of PECO's Proposed Rate HT Tail Block Energy Charge

Line	Description	Present Rates (1)	Proposed Rates (2)	PECO Proposed Increase Amount (3)	PECO Proposed Increase Percent (4)
1	Base Rate	3.7600¢	3.7500¢	(0.0100)¢	- %
2	Less: Embedded Fuel Cost	2.8753¢	2.1248¢	(0.7505)¢	(26)%
3	Nonfuel Rate	0.8847¢	1.6252¢	0.7405 ¢	84 %
4	Nonfuel Energy-Related Cost[a]	0.3122¢	0.4792¢	0.1670 ¢	53 %
5	Demand Cost Recovery	0.5725¢	1.1460¢	0.5735 ¢	100 %

(a) Unit Energy Cost[b]

	In Docket No. R-842590	In Docket No. R-85012
Embedded Fuel	2.8753	2.1248
Nonfuel Energy Cost	0.3122¢	0.4792¢

(b) Exhibit WFS-1

PHILADELPHIA ELECTRIC COMPANY

PAIEUG Recommended Design of Rate HT
(Before Phase-In)

Line	Description	Based on PECO Proposed Rate Spread (1)	Based on PAIEUG Recommended Rate Spread	
			Recommended Tail Block (2)	Equal Percent (3)
1	Customer Charge	$264.15	$281.50	$281.50
2	Capacity Charge	$ 10.40	$ 10.19	$ 10.20
	Energy Charge:			
3	First 150 Hours' Use	$ .0964	$ .0944	$ .0924
4	Next 150 Hours' Use	.0668	.0655	.0636
5	Additional	.0318	.0318	.0352
	High Voltage Discount:			
6	33 kV	$ .07	$ .07	$ .07
7	66 kV	.30*	.30*	.30*
8	Over 66 kV	.30*	.30*	.30*

*Plus 1% of Capacity and Energy Charges.

Note: The above values also reflect the recommended Rate HT Curtailment Credits developed in Schedule 10.

PHILADELPHIA ELECTRIC COMPANY

Analysis of the Relationship Between
Firm and Curtailable Service
at Present Versus Proposed Rates

Line	Description	Present Rates (1)	Proposed Rates (2)
1	Rate HT Curtailment Credit ($/kW)	$ 2.00	$ 2.00
2	Effective Rate HT Capacity Charge ($/kW)[a]	$ 13.515	$ 22.670
3	Curtailment Credit	15%	9%
	Monthly Nonfuel Power Cost (10,000 kW Maximum Registered Demand at a 90% Load Factor)		
4	Curtailable Service[b]	$188,273	$327,532
5	Firm Service	$197,273	$336,532
6	Credit for Curtailable Service	4.6%	2.7%

(a) Page 2 of 3

(b) 5,500 kW Firm capacity demand

PHILADELPHIA ELECTRIC COMPANY

Derivation of Rate HT Effective Demand Charge at 300 Hours' Use and Above for Present and PECO Proposed Rates

Line	Description	Present Rate (1)	Proposed Rate (2)
1	Capacity Charge ($ per kW)	$ 5.370	$ 9.440
	Energy Charge Less Tail Block:		
2	First 150 Hours' Use (per kWh)	.0363	.0589
3	Next 150 Hours' Use (per kWh)	.0180	.0293
4	Subtotal (per kWh)	.0543	.0882
5	Demand Component ($ per kW)[a]	8.145	13.230
6	Effective Capacity Charge ($ per kW)[b]	$13.515	$22.670

(a) Line 4 x 150 hours

(b) Line 1 + Line 5 (for proof that the Hours' Use and CDE formats are equivalent, refer to Page 3 of 3).

PHILADELPHIA ELECTRIC COMPANY

Proof of Equivalence Between Hours' Use and CDE Format
(10,000 kW Demand at 90% Load Factor)

Line	Description	Billing Units (1)	Rate (2)	Amount (3)
	Hours' Use Format			
1	Capacity Charge	10,000	$ 5.37	$ 53,700
	Energy Charge:			
2	First 150 Hours' Use	1,500,000	.0739	110,850
3	Next 150 Hours' Use	1,500,000	.0556	83,400
4	Additional	3,570,000	.0376	134,232
5	Total			$382,182
	CDE Format			
6	Effective Capacity Charge	10,000	$13.515	$135,150
7	Energy Charge	6,570,000	.0376	247,032
8	Total			$382,182

PHILADELPHIA ELECTRIC COMPANY

Recommended Rate HT Curtailment Credit

Line	Description	Based on PECO Allocation and Rate Design (1)	Based on PECO Allocation and PAIEUG Recommended Rate Design (2)	Based on PAIEUG Recommended Allocation and Rate Design (3)
1	Effective Rate HT Capacity Charge	$22.670	$25.340	$24.635
2	Curtailment Credit as a Percent of the Effective Capacity Charge	15%	15%	15%
3	Curtailment Credit	$ 3.40	$ 3.80	$ 3.70

COMMONWEALTH OF PENNSYLVANIA
BEFORE THE PUBLIC UTILITIES COMMISSION

THE PENNSYLVANIA
PUBLIC UTILITIES COMMISSION
V. PHILADELPHIA ELECTRIC
COMPANY

Docket No. R-850152

UP/UUC STATEMENT #2

TESTIMONY OF DR. S.L. FELDMAN
ON BEHALF OF THE
UTILITY USERS COMMITTEE/
UNIVERSITY OF PENNSYLVANIA

January 22, 1986

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January 22, 1986

TESTIMONY OF STEPHEN L. FELDMAN

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stephen L. Feldman. My business address is Suite 255, 3508 Market Street, University City Science Center, Philadelphia, PA 19104.

Q. WHO IS YOUR EMPLOYER AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am President of my own consulting firm, Delphi Energy Group, Inc. which specializes in the economics of energy, regulatory, and environmental problems. The firm has had clients in the U.S. and overseas. My primary responsibility, however, is as Director of the Energy Center of the University of Pennsylvania and Chairman of the Department of City and Regional Planning and my post as Associate Professor of City and Regional Planning. The Energy Center is the oldest and largest educational unit of its kind in the United States with over one hundred post-graduate students.

Q. WHAT IS YOUR EDUCATIONAL AND EMPLOYMENT BACKGROUND PRIOR TO YOUR PRESENT AFFILIATION?

A. I received my bachelors degree in 1968 from Rutgers University, whereupon I was awarded membership in the national economics honorary society. From 1968 to 1971, I attended the Johns Hopkins University School of Engineering and received a masters in geography and environmental engineering. In 1973, I completed my graduate work for the Ph.D. in geography from the Hebrew University. In 1972/73, I was an advisor to the Prime Minister's Office in Israel. From 1974 to 1977, I was Assistant Professor of Geography and Environmental Affairs at Clark University. In 1977, I was Visiting Professor in the Graduate

School of Public Policy at the University of California, and shortly thereafter was appointed Resident Scholar at the Russell Sage Foundation in New York City. In 1979, I was appointed to the School of Public and Urban Policy at the University of Pennsylvania.

Q. PLEASE DESCRIBE THE NATURE OF YOUR WORK IN ACADEMIA AND CONSULTING.

A. Since 1975, I have received over twenty funded research projects from federal, state, and local governments to perform analyses of the impact of energy technologies upon electric utilities and consumers. In addition, I have been a consultant to the Brookhaven and Lawrence Berkeley Laboratories on technology impact analysis, Pacific Gas and Electric Co., Wisconsin Power & Light Co. and Texas Utilities Co. on energy conservation, cogeneration, small power production and tariff policy. I have performed marginal cost analyses for fifteen utilities and have been advising the presidents of Tokyo Electric Power Co., Taiwan Electric Power Co., and the Korean Electric Power Co. on efficiency and productivity. I have testified before this Commission on a number of occasions representing either the Office of the Mayor of Philadelphia, the University of Pennsylvania, the Building Owners and Managers Association or the Utility Users Committee.

Q. HAS ANY OF YOUR WORK BEEN PUBLISHED?

A. Yes. I have published over twenty professional articles, three books, and four patents.

Q. DR. FELDMAN, WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I intend to prove to this Commission that the discrimination

against the non-manufacturing sector (commercial, institutional and high-rise residential HT customers) is not warranted in the present rate request by the Company. I will do this first by showing the importance of the non-manufacturing sector of our economy which is driving the economic growth of the region. Then I will show the impact of the proposed increase upon these customers and the effect upon the competitiveness of this sector. I will refer to the magnitude and potential job loss to the Philadelphia economy with special reference to the non-manufacturing sector. I will then show that this rate increase could have a severe impact on the Philadelphia economy and the future location of services in the area. Finally, I will describe how the tariff structure discriminates against PECo non-manufacturing customers to the advantage of manufacturing customers.

Q. CAN YOU BRIEFLY SUMMARIZE YOUR FINDINGS?

A. Yes. First, much of the economic growth in the Philadelphia area has been driven by a rapid rise in non-manufacturing services. Philadelphia is a regional and national center for many service-oriented sectors of the economy in such high technology fields as education, health, communications, banking and finance. Concurrently, the role of manufacturing in our economy has declined dramatically. Second, according to a recent national survey, utility costs in Philadelphia are the third highest among the twenty-five largest cities in the country. Third, the proposed rate increase will make Philadelphia's non-manufacturing rates the highest in the area, including New York

City. The non-manufacturing sector will have rates that are some sixty percent higher than the average of all the other Pennsylvania, New Jersey, Maryland and Delaware Interchange (PJM) utilities. Fourth, as a result of the rate increase, it has been estimated that there will be an employment loss impact of nearly 20,000 future jobs, at least sixty percent of whom will come from the non-manufacturing sector. Fifth, the Company is imposing a disproportionate share of the rate increase upon the commercial, institutional and high-rise residential HT customers--some twenty-six percent higher than manufacturing customers in this rate classes. This unfairness is compounded as a result of subsidies directly to manufacturers from the Economic Recovery and Employment Rider.

Q. HOW IMPORTANT IS THE NON-MANUFACTURING SECTOR TO THE PHILADELPHIA ECONOMY?

A. The non-manufacturing sector of the economy is rapidly rising and has gained prominence as the spur to economic growth. The definitive published study on the Philadelphia economy is a book co-authored by Professor Anita Summers, Economic Report on the Philadelphia Metropolitan Area, (University of Pennsylvania Press, 1985). Professor Summers was PECo's witness on economic impact in the Limerick II proceeding. According to Professor Summers, Philadelphia's current economic strength lies mostly in the non-manufacturing sector. The growth rates of trade and services have been high within the region, relative to the nation, and relative to other large SMSAs. It is the non-manufacturing sector that leads the area forward.

The growth of export-oriented services and affiliated

support services for manufacturing depend upon quality office space at reasonable prices. The location of services is sensitive to many factors, an important one of which is the cost of office space. Indeed, Philadelphia has until now been able to contain the increase in office space costs at levels which are highly competitive to other cities. The costs of office space factor as significant costs for these commercial and institutional enterprises. This competitive edge, however, becomes dulled as utility bills, the largest single component of office operating costs, outpaces the relative costs of other goods and services within the region and between Philadelphia and other regions. This provides a contributing factor for potential slowdown of this vital sector in this economy.

Q. DR. FELDMAN, CAN NON-MANUFACTURING BUILDING OWNERS PASS ON THE ELECTRIC RATE INCREASE TO THEIR TENANTS?

A. Unfortunately, unlike manufacturing activities where sunk costs in on-site plant and machinery can average over $100,000 per worker, non-manufacturing tenants have relatively low sunk costs. Therefore hi-tech non-manufacturing service companies have greater flexibility in choosing locations. Firms will be more prone to locate where office space is less expensive. Given that utilities comprise about forty percent of total office space operating costs, firms may certainly find space in Cherry Hill, Camden, Wilmington, etc., (areas which are close to Philadelphia markets), to be a better alternative than Philadelphia. Additionally, other operating costs cannot easily be pared if the costs of power rise since they involve factors such as security, maintenance, repairs, etc. Our own clients are deeply concerned

about this rate increase and, since many are part of large national companies, their dismay results in a hesitancy to promote continued growth within the City environs.

Q. WHAT WOULD BE THE RESULT OF A SLOWDOWN OF THE GROWTH OF THIS SECTOR?

A. Each firm's decision to relocate or to not locate in Philadelphia in the first place would impact upon PECo's estimate of its revenue requirements. These revenue shortfalls would have to be absorbed by PECo and/or offset by increased costs to other HT customers. The resultant increase in electric rates would force the price of electricity to increase further and would cause a decline in expenditures on goods and services. This would result in further decreased output and employment in the local economy.

Many commercial and other non-manufacturing services, such as educational institutions and hospitals do have significant sunk costs in plant and equipment. Instead of contemplating relocation, they would retrench. For example, recent estimates at the University of Pennsylvania show that the increase in student tuition required from the proposed rate increase would be two percent for all students. Penn's tuition closely tracks the other Ivy League institutions; therefore, such an increase could imply a budget cut for the academic departments in the University. In my own academic unit at the University, I oversee some two million dollars of educational and research activities annually. A two percent cutback would mean an almost equivalent loss in labor force. In other words, since I have almost 100 individuals on the payroll, I would be forced to reduce the

workforce by two employees. Since I have only one of more than 100 academic units on campus, the impact may be 175-200 jobs lost for the University at large.

To summarize: jobs would be lost, city wage tax revenues would decline, disposable income would be reduced, local consumption of goods and services would be reduced and the Philadelphia economy would become less competitive. This would mean a lower growth rate for the Philadelphia economy.

Q. DR. FELDMAN, WHAT ARE THE EMPLOYMENT IMPACTS OF THE PROPOSED RATE REQUEST OF THE COMPANY UPON THE NON-MANUFACTURING SERVICES SECTOR OF PHILADELPHIA?

A. Estimates of the impacts have been presented by City of Philadelphia witness Dr. Arie P. Schinnar. Dr. Schinnar's forecast of job loss is 19,196. His figure 4 on page 19 (City Statement No. 1) shows that even though manufacturing comprises twenty percent of the labor force, it only incurs seven percent of the job loss. On page 20, he states that the bulk of the job loss will occur in managerial, clerical, professional, technical and service job categories within the City of Philadelphia. These sectors account for two-thirds of the job losses. He also states on page 22, that the service sectors most affected will be hotels and lodging; health services; advertising and business services; finance, insurance and real estate; and retail trade. These constitute primarily the larger non-manufacturing HT and PD customers. Not having done an independent study, I would accept his method as a valid approach.

Q. WHAT IS THE CURRENT SITUATION WITH RESPECT TO THE COSTS INCURRED BY NON-MANUFACTURING CUSTOMERS IN PHILADELPHIA?

A. Comparisons can be made of Philadelphia's non-manufacturing

customers' costs of office space to similar customers of other utilities in major metropolitan areas. The Building Owners and Managers Association (BOMA) performed a survey in 1985 which illuminates the high costs incurred by Philadelphia commercial building owners even prior to any rate increase this Commission may grant the Company. Figure SLF__1 (Key Table SLF__1) gives the breakdown of the average dollar per square foot total utility cost expended by commercial building owners in twenty-five cities. At the present the U.S. average is $1.84 per square foot. The chart indicates that Philadelphia ranks third highest with a cost of $2.39 per square foot. Only New York and Hartford have higher costs of $2.88, and $2.52, respectively. Of the same twenty-five cities, Figure SLF__2 shows that Philadelphia ranks fifth in dollars per square foot of total operating expenses falling behind only New York, Wilmington, Hartford and Newark. This data, once again, does not take into account the thirty to thirty-six percent increase to building owners in Philadelphia as requested by the Company. It appears from the data that Philadelphia is competitive with other cities in other major cost elements; it is the cost of utilities that hampers the competitiveness of office space here. The BOMA report examines all utility services. In order to measure the impact of the electric rate increase, an analysis was performed comparing non-manufacturing and manufacturing customers within PECo and across other utilities.

Q. HOW DID YOU PERFORM A COMPARISON BETWEEN UTILITIES OF NON-MANUFACTURING CUSTOMERS' TARIFFS?

A. I performed the analysis using the data and methodology that

appears in Dr. Wirtshafter's testimony on inter-utility comparisons.

Q. WHAT DID A COMPARISON OF NON-MANUFACTURING CUSTOMERS' TARIFFS SHOW?

A. Figure SLF__3 shows that PECo's rates presently are the second highest of the PJM customers for the non-manufacturing class with the sole exception of Jersey Central Power and Light Co.. However, PECo would surpass Jersey Central Power & Light if a rate increase of only 11.5 percent or greater were granted to the Company.

Examination of Figure SLF__4 reveals that after the rate increase, non-manufacturing rates for PECo would be on average 60.7% higher than rates of the other PJM utilities. If we remove the University of Pennsylvania from the analysis (its rate increase is somewhat less than other non-manufacturing customers), the figure rises to 67.9%. Rates that are 60 percent higher on average show the tremendous differential that will exist between PECo and its neighboring utilities for the typical large non-manufacturing customer.

SLF__5 shows that, on average, if the University of Pennsylvania would be located in any other area, its annual electric bill would be reduced from nearly $18,700,000 to some $12,200,000. That is a difference of nearly $430 per student per year.

Q. HOW DO THE OTHER UTILITIES WHICH YOU STUDIED TREAT THIS DIFFERENTIAL BETWEEN MANUFACTURING AND NON-MANUFACTURING HT CUSTOMERS?

A. A review of the PJM utilities and Duquesne was performed to measure this treatment. The ratios developed indicate the

relative treatment of non-manufacturing to manufacturing across utilities. These are shown in Figure SLF__6. The ratio of non-manufacturing to manufacturing is significantly greater with those utilities which utilize a ratchet for this customer class, i.e. PECo and Delmarva Power and Light (Met Ed has a ratchet, but the effect is very slight). Given the proposed rate increase PECO emerges as having the highest discrepancy between non-manufacturing and manufacturing customers.

Q. DID YOU ANALYZE THE IMPACT OF PECO'S PROPOSED RATE INCREASE AS IT PERTAINS TO THE MANUFACTURING AND NON-MANUFACTURING SEGMENTS OF THE HT CLASS?

A. This particular question is a primary concern in Dr. Wirthshafter's testimony. However, for completeness, I have included in my testimony a brief summation of the variation in treatments by PECo of the two subclasses.

Q. WHAT DOES YOUR SUMMARY SHOW?

A. From PECo's data (Attachment IV-D-2), at 1300 Kw of demand, it is clear that a customer who uses 600 hours would experience a rate increase of 26.1 %, while a customer who uses 400 hours would experience a 32.8 % increase--an increase which is 26 % greater than that received by his counterpart. When actual customer bills are examined, the differences could be even greater due to the effects of the demand ratchet. Figure SLF__7 is illustrative of this fact. It shows the actual increase to twelve UUC members and two hypothetical manufacturing customers. The differentials depicted on this figure are caused by a combination of effective use hours and the imposition of the demand ratchet.

Such an impact might be acceptable if it were necessitated by

the manner in which the Company incurs its costs. However, as demonstrated by Dr. Wirtshafter in his testimony, such is not the case for PECo. The results would deviate further if we assumed the application of special riders created for the manufacturing customer class.

Q. WHAT RIDERS FOR MANUFACTURING CUSTOMERS ARE YOU REFERRING TO?

A. I am specifically referring to the Economic Recovery and Employment Rider (known as E2R2). Manufacturing customers are eligible for discounts on the purchase of additional power over a previously computed Base Period Energy Billing when their mean employment has increased over that of the base period. This further reduces the tail block energy charges paid by manufacturing customers who qualify for this rider.

Even large manufacturing customers have argued against this tariff before this Commission stating that it departs from the cost of service pricing methodology normally employed by the Company. This type of incentive for manufacturers to consume additional energy at reduced rates is being subsidized by other HT customers. Our economy has recovered from the deep recession during which time the Commission approved the rider. It is now time to revoke it, especially in light of the testimony of City witness Dr. Schinnar who shows that the impact of the rate increase affects the non-manufacturing sector of our economy more adversely than it does the manufacturing sector.

Q. DR. FELDMAN, WHAT ELSE DO YOU RECOMMEND TO CORRECT THE INEQUITY IMPOSED UPON THE NON-MANUFACTURING HT CUSTOMER CLASSES?

A. My colleague, Dr. Wirtshafter, and I are in agreement that

reductions in demand charges and the elimination of the attendant ratchet are justified. These changes would narrow the gap between manufacturing and non-manufacturing consumers and the gap between what non-manufacturing customers are charged by PECo versus what they would be charged by other utilities in the PJM area and the other parts of the United States. I therefore advocate the elimination of the ratchet and a reduction in the demand charges. The specific recommendations are contained in Dr. Wirtshafter's testimony.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

TABLE SLF 1

ECONOMIC COMPARISON OF UTILITY COSTS AND TOTAL OPERATING EXPENSES
FOR COMMERCIAL OFFICE BUILDINGS IN VARIOUS U.S. CITIES

code	city	avg $/sq. ft on utilities	total operating expenses $/sq. ft)
1	BALTIMORE	2.38	5.89
2	BOSTON	1.81	5.40
3	BUFFALO	1.80	4.56
4	CHICAGO	1.76	5.41
5	CINCINNATI	1.60	4.41
6	CLEVELAND	1.69	5.04
7	DALLAS	2.05	4.64
8	DETROIT	1.99	4.58
9	HARTFORD	2.52	6.01
10	HOUSTON	1.59	4.14
11	LOS ANGELES	1.65	5.52
12	MILWAUKEE	1.35	4.60
13	MINNEAPOLIS	1.51	4.59
14	NEW YORK	2.88	7.55
15	NEWARK	1.97	5.99
16	NORFOLK	1.69	3.86
17	PHILADELPHIA	2.39	5.96
18	PITSSBURGH	1.75	5.49
19	PLAINFIELD,N.J.	2.00	4.46
20	SAN FRANCISCO	1.67	5.83
21	SEATTLE	0.65	3.41
22	ST. LOUIS	2.25	4.43
23	SYRACUSE	1.41	3.19
24	D.C.	1.52	3.95
25	WILMINGTON	2.03	7.36
	U.S. AVG.	1.84	5.05

Source: 1985 BOMA Experience
Exchange Report,
Washington DC

AVERAGE UTILITY COSTS

FOR VARIOUS CITIES – IN ASCENDING ORDER

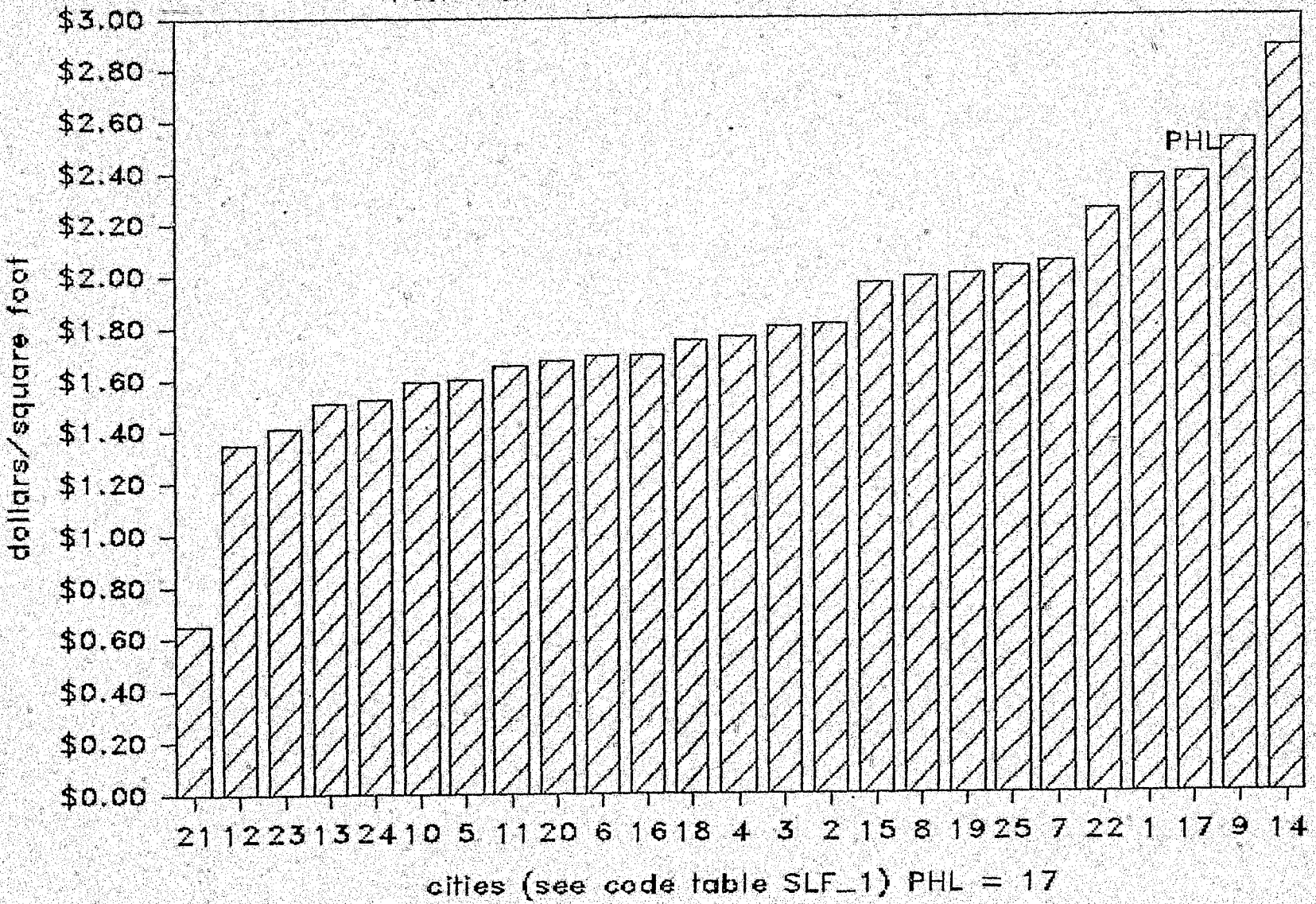
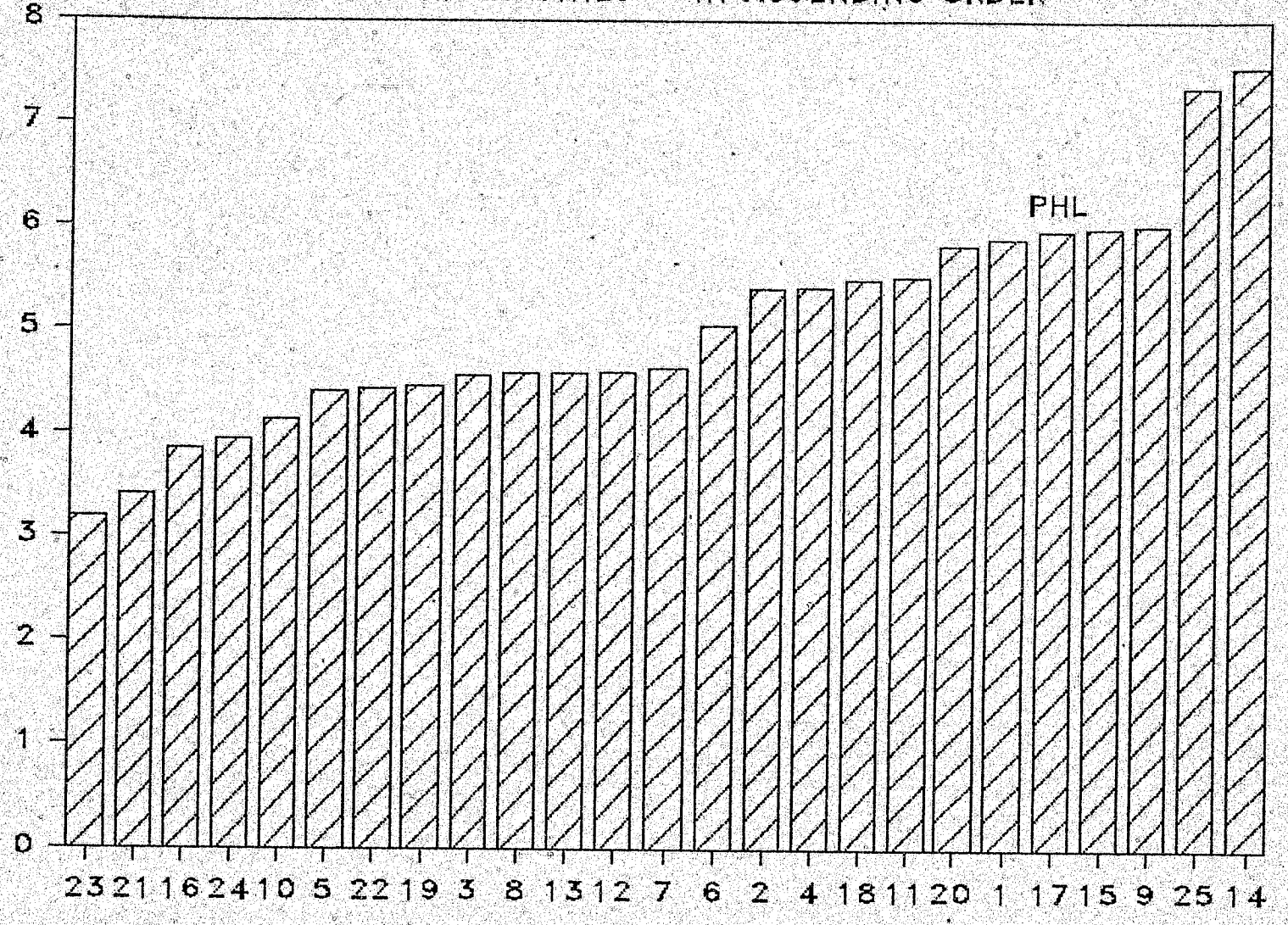


FIGURE SLF__1

urce: 1985 BOMA Experience Exchange Report

TOTAL OPERATING EXPENSES

FOR VARIOUS CITIES – IN ASCENDING ORDER



urce: 1985 BOMA Experience Exchange Report

FIGURE SLF 2

TABLE SLF 3

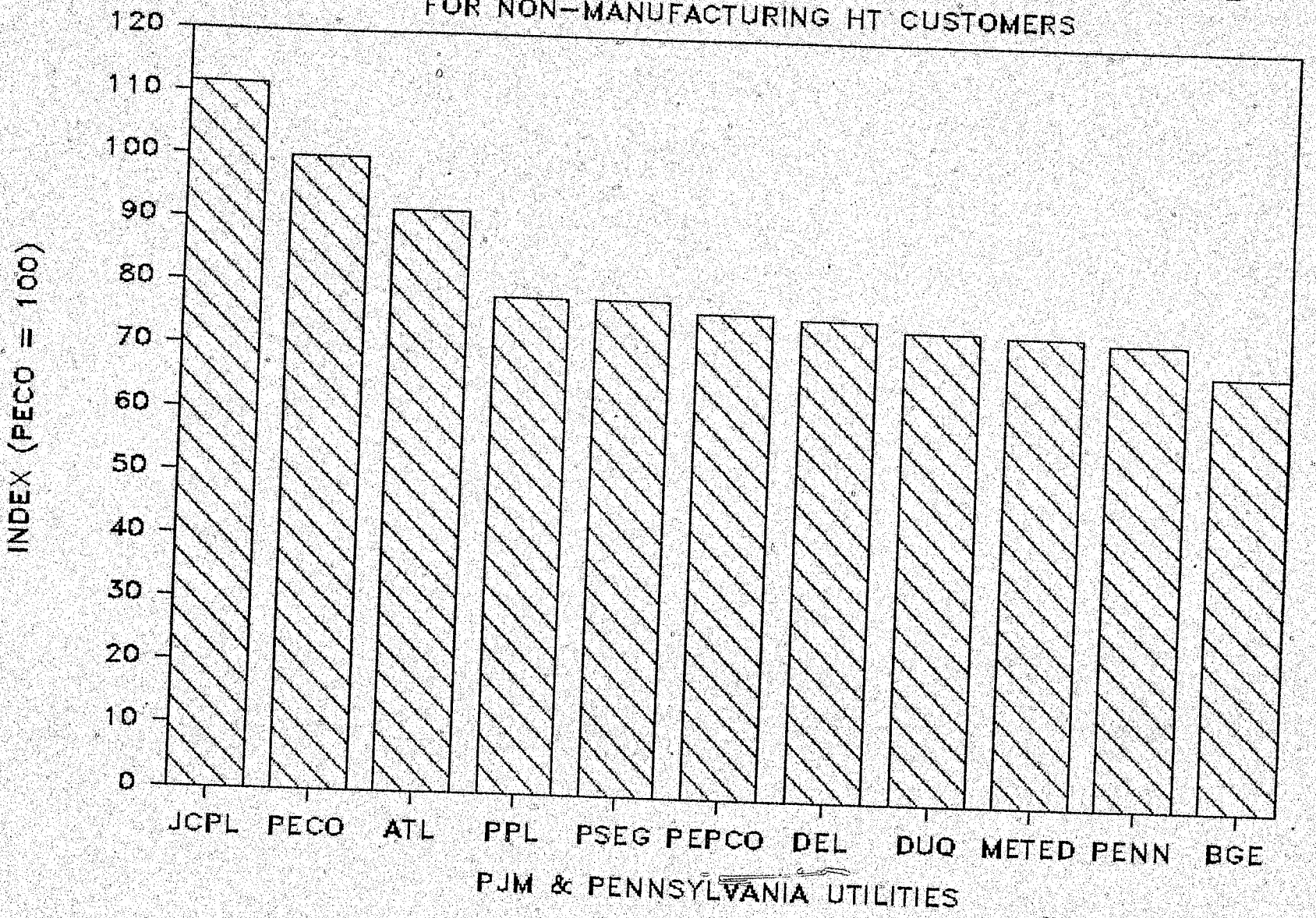
COMPARISON OF PRESENT RATES
For non-manufacturing HT customers
in different utility service territories

INDEX (PECO=100)

		present rates
1	Jersey Central Power & Light	111.50
2	Philadelphia Electric Co.	100.00
3	Atlantic Electric	91.73
4	Pennsylvania Power & Light	78.39
5	Public Service Electric & Gas	78.34
6	Potomac Electric Power Co.	76.64
7	Delamarva Power & Light	76.13
8	Duquesne Light Co.	74.51
9	Metropolitan Edison	74.14
10	Pennsylvania Electric	73.26
11	Baltimore Gas & Electric	68.60

COMPARISON OF PRESENT RATES

FOR NON-MANUFACTURING HT CUSTOMERS



rce: Utility Rate Schedules

FIGURE SLF 3

TABLE SLF 4

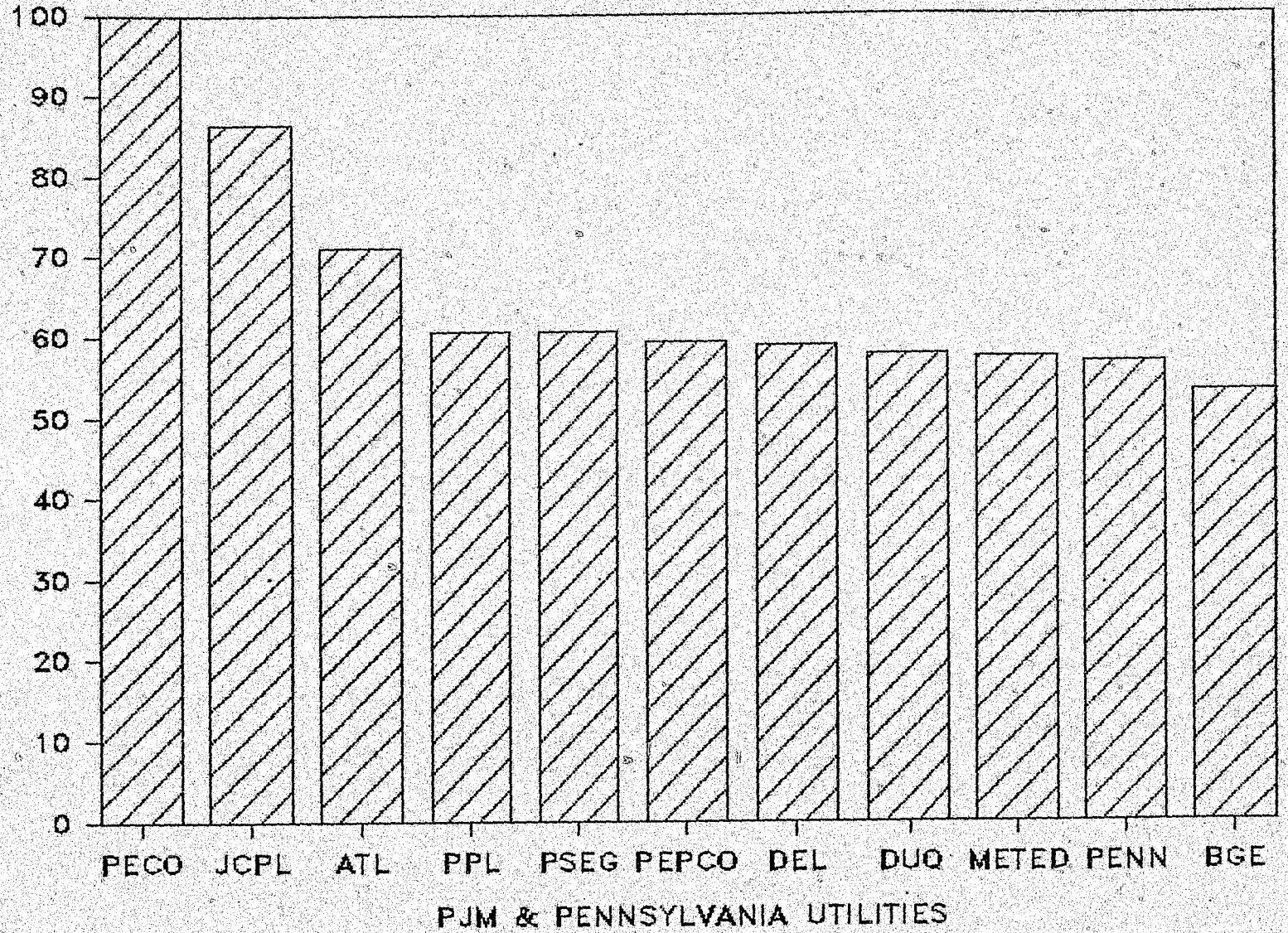
COMPARISON OF PROPOSED RATES
For non-manufacturing HT customers
in different utility service territories

INDEX (PECO=100)

		proposed rates
1	Philadelphia Electric Co.	100.00
2	Jersey Central Power & Light	86.34
3	Atlantic Electric	71.04
4	Pennsylvania Power & Light	60.70
5	Public Service Electric & Gas	60.66
6	Potomac Electric Power Co.	59.34
7	Delamarva Power & Light	58.95
8	Duquesne Light Co.	57.70
9	Metropolitan Edison	57.41
10	Pennsylvania Electric	56.73
11	Baltimore Gas & Electric	53.12

COMPARISON OF PROPOSED RATES

FOR NON-MANUFACTURING HT CUSTOMERS



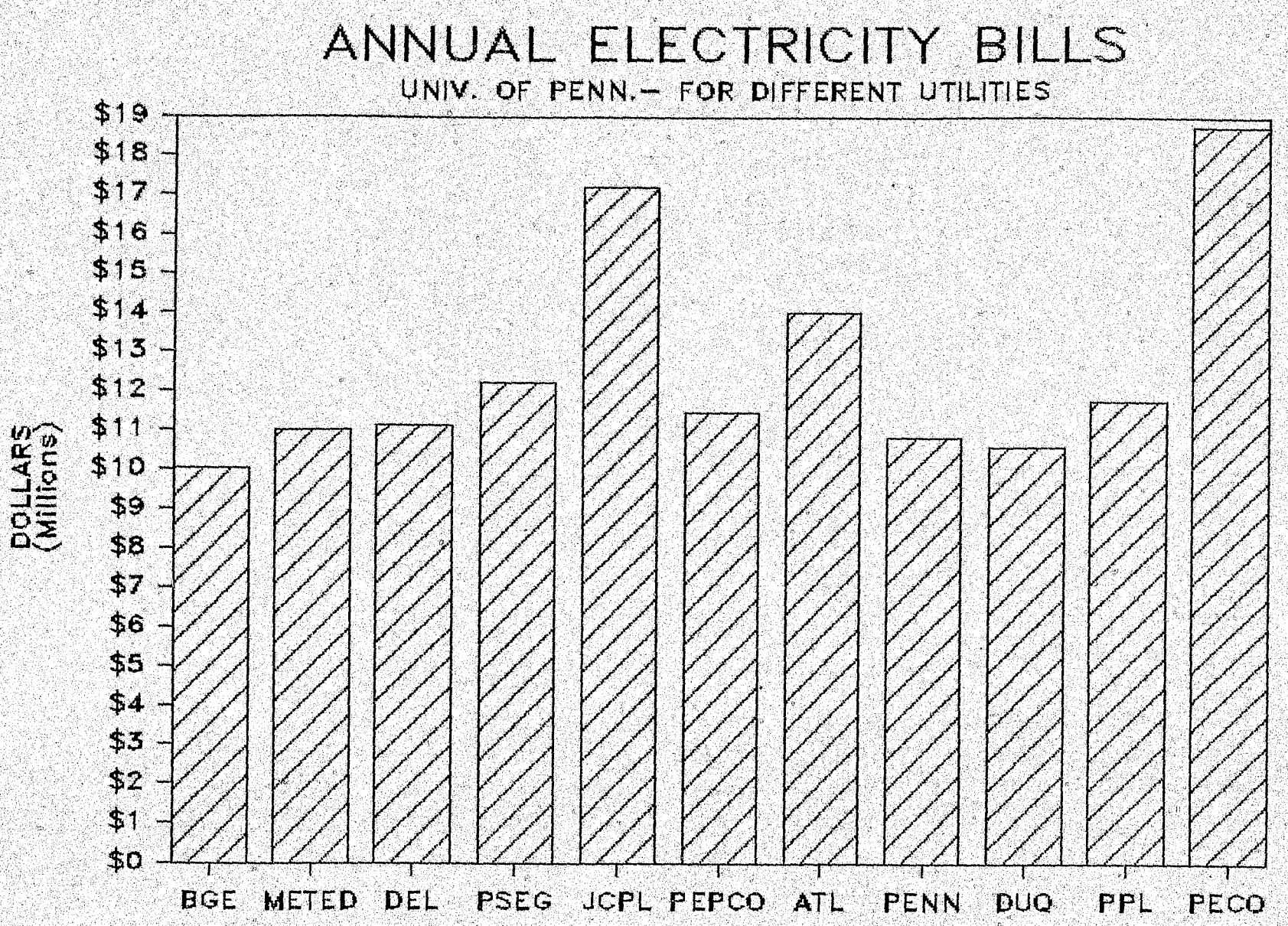
rce: Utility Rate Schedules

FIGURE SLF 4

TABLE SLF 5

TOTAL YEARLY ELECTRIC BILLS FOR UNIVERSITY OF PENNSYLVANIA
For different utility service territories
(PECo after requested rate increase)

Baltimore Gas & Electric	$10,048,478.00
Metropolitan Edison	$11,016,106.00
Delamarva Power & Light	$11,133,222.00
Public Service Electric & Gas	$12,228,310.00
Jersey Central Power & Light	$17,206,368.00
Potomac Electric Power Co.	$11,450,754.00
Atlantic Electric	$14,013,511.00
Pennsylvania Electric	$10,810,643.00
Duquesne Light Co.	$10,576,070.00
Pennsylvania Power & Light	$11,771,491.00
Philadelphia Electric Co.	$18,747,700.00



rce: Univ. of PA electric bills & utility rate schedules.

FIGURE SLF 5

TABLE SLF 6

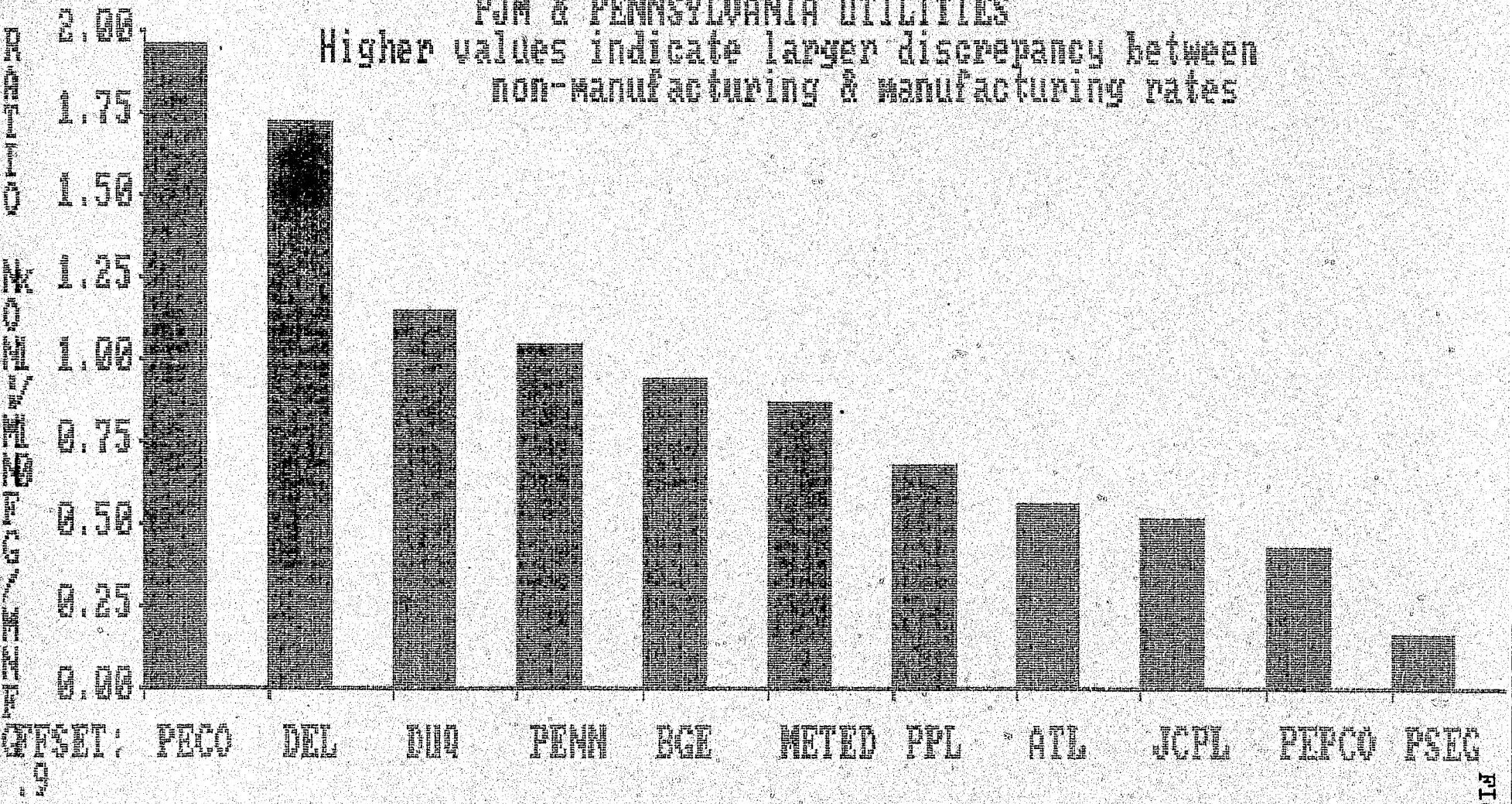
RELATIVE TREATMENT OF NON-MANUFACTURING & MANUFACTURING CUSTOMERS
BY PJM & PENNSYLVANIA UTILITIES

Higher values indicate large discrepancy between non-manufacturing & manufacturing rates

UTILITIES	RATIO NON-MANUFACTURING/MANUFACTURING
Philadelphia Electric Co.	1.09687
Delmarva Power & Light	1.07216
Duquesne Light Co.	1.01498
Pennsylvania Electric	1.00571
Baltimore Gas & Electric	0.99527
Metropolitan Edison	0.98695
Pennsylvania Power & Light	0.96831
Atlantic Electric	0.95634
Jersey Central Power & Light	0.95243
Potomac Electric Power Co.	0.94294
Public Service Electric & Gas	0.91630

RELATIVE TREATMENT OF NON-MANUFACTURING & MANUFACTURING CUSTOMERS BY PJM & PENNSYLVANIA UTILITIES

Higher values indicate larger discrepancy between non-manufacturing & manufacturing rates



Source: UUC member electric bills & hypothetical Mnfg. bills/Analysis of utility rate schedules.

PJM & PENNSYLVANIA UTILITIES
RATIO NON-MNFG/MNFG

FIGURE SLF — 6

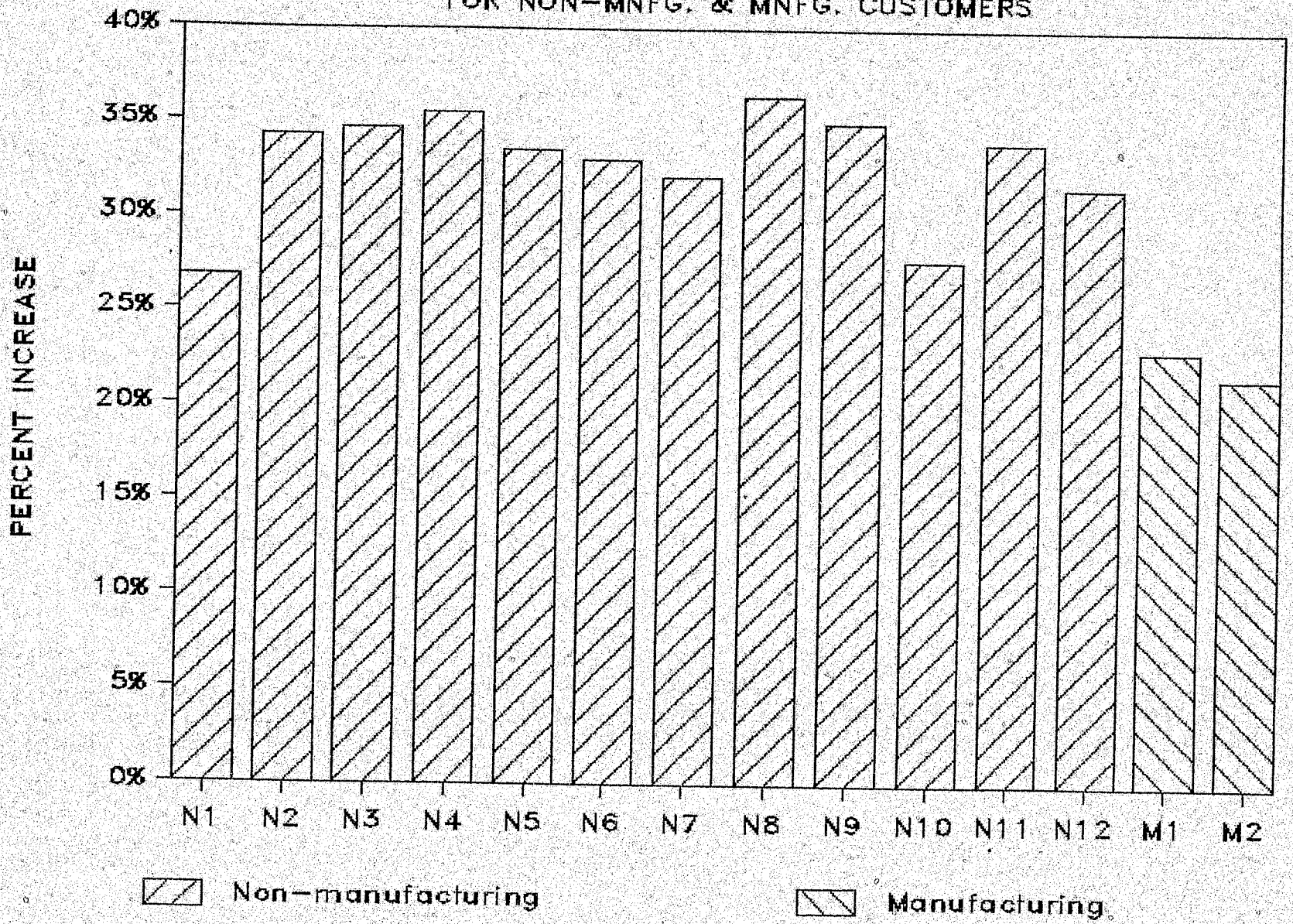
TABLE SLF__7

PERCENT RATE INCREASE
For non-manufacturing & manufacturing customers
(code: N=non-mnfg., M=mnfg.)

N1	26.84%
N2	34.27%
N3	34.69%
N4	35.50%
N5	33.53%
N6	33.00%
N7	32.11%
N8	36.42%
N9	35.02%
N10	27.69%
N11	33.97%
N12	31.65%
M1	22.97%
M2	21.60%

PERCENT RATE INCREASE

FOR NON-MNFG. & MNFG. CUSTOMERS



ce: UUC member electric bills & hypothetical mnfg. bills/ Analysis of PECo rate request.

FIGURE SLF 7

SUTHERLAND, ASBILL & BRENNAN
1666 K STREET, N. W.
WASHINGTON, D. C. 20006-2803
(202) 872-7800

CABLE: SUTAB WASHINGTON
TELEX: 89-501
XEROX 485- (202) 887-3443
XEROX 495- (202) 887-3444
DEX 3600- (202) 293-1254

FIRST ATLANTA TOWER
ATLANTA, GEORGIA 30383-3001
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January 22, 1986

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SECRETARY'S OFFICE
Public Utility Commission

Secretary
Pennsylvania Public
Utility Commission
P.O. Box 3265
North Office Building
Commonwealth & North Streets
Harrisburg, Pennsylvania 17120

Re: Pennsylvania Public Utility Commission
v. Philadelphia Electric Company
Docket No. R-850152

Dear Sir:

Enclosed please find the original plus two conforming copies of a document entitled "Testimony of James A. Ross on Behalf of Occidental Chemical Corporation." Also, enclosed please find an additional copy of this document. We would appreciate it if your office would time stamp it and return it to us in the enclosed self-addressed envelope for our files.

Sincerely,

Earle H. O'Donnell

Earle H. O'Donnell
Merrill L. Kramer

Attorneys for
Occicental Chemical
Corporation

Enclosures

DOCUMENT FOLDER

CERTIFICATE OF SERVICE

I hereby certify that I have this 21st day of January, 1986, served a copy of the foregoing document upon the following by first class mail, postage prepaid:

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James A. Ross

Dated: January 21, 1986

Subscribed and sworn to before me this 21st day of January, 1986.

Virginia D. Robinson
Notary Public

My Commission expires March 4, 1988.

RECEIV

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

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Public Utility Com

PHILADELPHIA ELECTRIC COMPANY

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Testimony

of

JAMES A. ROSS

On behalf of

Occidental Chemical Corporation

January 1986
Project 4066

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

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Summary of Testimony of James A. Ross

Q PLEASE SUMMARIZE YOUR TESTIMONY.

A The testimony which I present addresses the appropriate prices and provisions for providing supplementary power, back-up power and maintenance power to PECO customers. In my testimony, I discuss the basic principles and practices which should be employed in the determination of rates to be paid by PECO for these types of service. Furthermore, the testimony presents specific tariff schedules detailing the appropriate prices and provisions for providing these types of service. I have discussed both the appropriate service provisions and the appropriate rates for each of these types of service.

Conclusions and Recommendations

Q WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS:

A My conclusions and recommendations regarding service provisions are as follows:

1. PECO customers whose electric requirements may be provided by a non-utility generation facilities including cogeneration and small power production facilities (collectively referred to as "cogeneration") have a potential need for supplementary power, back-up power and maintenance power. PECO should provide these types of service on a nondiscriminatory basis which reflects the cost of providing each type of service.

2. The tariff language setting forth the provisions under which these types of service are provided should clearly reflect the intent of the provisions. Based upon my understanding of Mr. Sundermier's testimony, I agree with PECO's policies regarding written permission for parallel operation and customer cost responsibility for additional distribution facilities. In order to clarify these policies in the tariff language, I recommend that the parallel operation provision be as follows:

> The customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occassioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the customers installation in accordance with Tariff Rule 9.3.

With regard to additional distribution facility cost responsibility, I recommend the following:

> Investment in additions or changes to Company distribution facilities required to provide this service, that is over and above the investment that is normally incurred to provide service to such a customer assuming the customer were to obtain its full requirements from the Company in accordance with the rules and regulations, will be paid by customer.

3. I urge this Commission to modify the availability provisions associated with the supply of supplementary power, back-up power and maintenance power to read as follows so that all customers receiving cogenerated power has access to these services:

Availability.

To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

4. The Commission should eliminate the "Control of Supply Provision" as set forth in the Auxiliary Service Rider (and Scott Exhibit No. 1) and adopt the Excess Supply provision shown in Schedule 8 of Exhibit JAR-1 ( ). The provision presented in Schedule 8 addresses the PECO concern pertaining to electrical power consumption in excess of contract amount without requiring devices to physically limit the sale of power.

5. Maintenance power should be made available on a firm basis. Although the currently-effective Auxiliary Service Rider does not provide for firm maintenance power, the revised version of the Rider as shown in Scott Exhibit No. 1 (Revised Rider) clearly indicates a willingness on the part of PECO to provide maintenance power on a firm basis. Further, consistent with the Revised Rider, I recommend that the 1,000 kW minimum capacity requirement and the limitation on the duration and frequency of maintenance power be eliminated.

6. I recommend that the Commission review the Liability Provision in the Auxiliary Service Rider to determine whether it is discriminatory and imposes excessive risks on cogenerators. If similar liability requirements are not imposed on others operating in parallel with PECO, the current provision should be deleted and replaced by an even-handed provision. Such a provision could read as follows:

> Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such parties negligent operation or use of electrical facilities used in connection with the provisions of this service.

Q WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY WITH REGARD TO THE APPROPRIATE RATES THAT SHOULD BE PAID FOR SUPPLEMENTARY, BACK-UP AND MAINTENANCE POWER?

A To summarize:

1. I agree with PECO's position that the normal service rate and applicable riders is an appropriate basis for pricing supplementary power. However, it is not appropriate to bill supplementary power in combination with back-up power as required by the Auxiliary Service Rider (and the Revised Rider). This combination billing practice should be prohibited.

2. The application of the "normal service rate and applicable riders" for back-up power as prescribed by the PECO Auxiliary Service Rider (and Revised Rider) is inappropriate and ignores the capacity supplied by cogeneration facilities. The effect of the back-up power provision in both the effective Auxiliary Service Rider and the Revised Rider is to assess excessive charges for back-up power and to potentially discourage cogeneration development.

3. Analyses to demonstrate that the PECO Auxiliary Service Rider reflects the probability that back-up service will or will not contribute to the need for and the use of utility capacity as required by the FERC have not been performed by PECO (see Occidential Chemical Exhibit No. 1 and Company testimony Tr. 1679). Further, as demonstrated by Schedule 3 of Exhibit JAR-1 ( ), there is an inherent simultaneous outage assumption in both the Auxiliary Service Rider and the Revised Rider--an assumption which is inconsistent with the FERC and PUC rules.

4. Back-up power charges under the PECO Riders can vary significantly for customers purchasing the same amount of power . Schedule 4 of Exhibit JAR-1 ( ) illustrates that the difference in charges could be over 85%.

5. Back-up power rate based upon the daily proration (of the otherwise applicable) firm rate is reasonable, provides protection to the other PECO ratepayers and should be adopted as the basis for pricing back-up service when taken by a cogenerator. The appropriate rate should contain a minimum payment provision which, if based on PECO's full requested revenue level, is the monthly rate

of $3.35 per kW times the contract capacity for back-up power. Schedule 5 of Exhibit JAR-1 ( ), shows the development of the $3.35 per kW charge. (If the approved rate level is less than requested, this charge should be appropriate reduced to reflect the approved rate level.)

6. Scheduled Maintenance Power should be provided during the off-peak nonsummer months and should be priced at the (otherwise applicable) daily prorated firm rate that incorporates a 0.50 Scheduling Provision Factor to reflect the cost to provide this off-peak type service. Schedule 6 of Exhibit JAR-1 ( ), illustrates the calculation of the scheduled maintenance power payment under the appropriate rate for Scheduled Maintenance Power. This schedule also illustrates the method of proration that would apply to both scheduled maintenance power and back-up power under my proposal.

7. I recommend that PECO be required to provide interruptible back-up and maintenance service on an "as-available" basis, in order to recognize the varying service needs of cogenerators and to encourage the development of qualifying facilities. The appropriate rate for this type of service is the Company's hourly PJM billing rate plus a 10% adder.

8. I recommend that the Commission implement the specific rate schedules presented in Schedules 7, 8, 9 and 10 of Exhibit JAR-1 ( ), which incorporate my recommendations regarding the appropriate prices and provisions for providing service on both a firm and interruptible basis.

Testimony to supplement that which is provided in this direct testimony may be necessary upon receipt of information which has been requested from PECO.

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Testimony of James A. Ross

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James A. Ross, 605 Old Ballas Road, St. Louis, Missouri.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation with the firm of Drazen-Brubaker & Associates, Inc., utility rate and economic consultants.

Q WOULD YOU PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE?

A This is set forth in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Occidental Chemical Corporation.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to address the various aspects of the Philadelphia Electric Company (PECO) tariff pertaining to the

supply of supplementary power, back-up power and maintenance power to PECO customers. My testimony also sets forth the basic principles and practices which should be employed in the determination of rates to be paid by PECO customers for supplementary power, back-up power and maintenance power. I shall discuss some of the more fundamental, theoretical and practical considerations attendant to the determination of the appropriate prices and provisions for these types of service. Furthermore, the testimony presents specific tariff schedules detailing the appropriate prices and provisions for providing these types of service.

Failure to specifically address an aspect of the PECO rates, rules and regulations pertaining to these types of service should not be construed as an endorsement of that aspect.

Supplementary, Back-up, and Maintenance Power

Q WHAT TYPES OF SERVICE DOES A PARTIAL REQUIREMENTS CUSTOMER NEED FROM THE UTILITY?

A Utility customers whose electric requirements may be provided by non-utility generation including cogeneration and small power production facilities (collectively referred to hereafter as "cogeneration") have a potential need for at least three types of service from the utility. The FERC regulations (18 CFR, Part 292) identify these services as supplementary power, back-up power, and maintenance power.

Q WHAT IS SUPPLEMENTARY POWER?

A Supplementary power is power supplied by the utility to the customer in addition to that which is supplied by cogeneration and power production resources. For example, a customer with a total requirement of 60,000 kW may satisfy 40,000 kW with cogeneration and purchase the remaining 20,000 kW from the utility as supplementary power. Supplementary power is typically used consistently throughout the year.

Q WOULD THE CHARACTERISTICS OF A SUPPLEMENTARY POWER CUSTOMER BE SIMILAR TO THE CHARACTERISTICS OF A REGULAR TOTAL REQUIREMENTS CUSTOMER?

A Yes. Both customers require a continuous firm supply of power. Further, the load imposed upon the utility system for both of these customers is a function of the electrical consumption requirements of the customer.

Q WHAT IS MAINTENANCE POWER?

A Maintenance power is power supplied by the utility to replace the generation from cogeneration facilities when those facilities are scheduled out of service for maintenance. This type of power would normally be provided on a pre-arranged schedule basis to allow equipment to be taken out of service for routine inspections and preventive maintenance.

Two important characteristics of maintenance power are that

the service is only required for short durations (typically not more than a month) and the time at which load is imposed on the utility system is controllable. This means that supply of maintenance power can be arranged at a time when the utility has idle capacity available. As will be discussed later, this is an important cost-causative characteristics which should be reflected in the rate paid for this power.

Q WHAT IS BACK-UP POWER?

A Back-up power is power that is supplied by the utility to replace generation ordinarily provided by cogeneration equipment during periods of unscheduled outage.

Unlike supplementary power, the need for back-up power is a function of random equipment outages associated with generation facilities (and the time required to return the equipment to service). Further, back-up power differs from maintenance power in that back-up power cannot be scheduled.

Q IS THE NEED FOR BACK-UP POWER UNIQUE TO COGENERATION?

A Absolutely not. Utility generation equipment sustains forced and partial outages as a routine course of operation. Such outages require that the utility maintain sufficient reserves in order to accommodate these regular occurrences. The supply of back-up power to a cogenerator requires the use of reserves in the same manner as the reserves back-up a utility generating resources

during an unscheduled outage. The utility outage and the cogeneration outage both occur randomly and are directly related to the performance of generating equipment.

Q HOW DO THESE TYPES OF SERVICE DIFFER FROM REGULAR UTILITY SERVICE?

A Usually, a customer requiring electricity purchases all of his or her requirements from the utility ("total requirements customer"). The service required by a customer receiving power from cogeneration may differ from regular utility service in several ways.

First, the cogeneration might not provide all of a customer's electrical power requirements ("partial requirements customer"). This customer, therefore, requires supplementary power from the utility on a continual basis.

Second, there will be periods when the cogenerating equipment has to be taken out of service for maintenance. Unless the partial requirements customer reduces his use of electricity, the utility will be called upon to provide maintenance power. In this case, the utility will be supplying all, or part, of the load on an intermittent basis for a period which normally has been previously scheduled with the utility.

Finally, all generating equipment is subject to being taken out of service due to equipment failures. Such failures occur on a random basis and occasion the need for back-up power to be provided by the utility.

Q HAS THE FERC AND THE PENNSYLVANIA PUBLIC UTILITY COMMISSION (PUC) ESTABLISHED SPECIFIC CRITERIA FOR DEVELOPING RATES FOR BACK-UP AND MAINTENANCE POWER?

A Yes. In addition to stating that back-up and maintenance power rates shall be nondiscriminatory and provided upon request, the FERC rules in Section 292.305(c) also state:

> (c) Rates for sales of backup and maintenance power. The rate for sales of backup power or maintenance power:
>
> (1) shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and
>
> (2) shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

The PUC rules state in Section 59.35(c) and (d) that:

> (c) A utility's rate for sales of back-up power to qualifying facilities shall not be based upon an assumption that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously or during the system peak, or both, unless supported by factual data.
>
> (d) A utility's rate for sales of maintenance power to qualifying facilities shall include all energy costs and a demand or capacity charge not in excess of a charge required to recover the appropriate transmission plant and full distribution plant costs. When the scheduled outages of a qualifying facility cannot be scheduled during other than utility peak periods, the demand or capacity charge shall be the full charge stated in the utility's filed tariff under which the qualifying facility receives such service.

Service Provisions

Q HAVE YOU REVIEWED PECO'S AUXILIARY SERVICE RIDER?

A Yes, I have. The Auxiliary Service Rider, effective September 25, 1984, is presented in Schedule 1 of Exhibit JAR-1 ( ). In addition to the September 25, 1984 Auxiliary Service Rider, I have reviewed the revised version of this Rider (Revised Rider) filed with this Commission on December 27, 1985. The Revised Rider was entered into the record in this proceeding as Scott Exhibit No. 1 and is presented in Schedule 2 of Exhibit JAR-1 ( ).

Q HAVE YOU ALSO REVIEWED THE TESTIMONY OF PECO WITNESS WILLIAM SUNDERMIER?

A Yes, I have. Although Mr. Sundermier has provided testimony in this proceeding clarifying certain of PECO's policies addressed in both the Auxiliary Service Rider and the Revised Rider, the actual language implementing such policies is ambiguous in both riders.

Q SHOULD THE TARIFF LANGUAGE CLEARLY REFLECT THE STATED PECO POLICIES?

A Yes, it should. PECO has stated that the tariff contains the only written statement of PECO's policy regarding the supply of supplementary, back-up or maintenance power (Tr. 1690-91). Thus, unambiguous tariff language is essential to customer understanding of these PECO policies.

Q WHAT ARE YOUR RECOMMENDATIONS WITH REGARD TO CLARIFYING THE TARIFF LANGUAGE?

A On cross-examination, Mr. Sundermier explained PECO's policies regarding written permission for parallel operation and customer cost responsibility for additional distribution facilities. Based on my understanding of his testimony, I concur with the stated PECO policies. However, the tariff language does not clearly reflect the Company intent as explained by Mr. Sundermier. I therefore recommend that the tariff language related to parallel operation be as follows:

> The Customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

With regard to additional distribution facility cost responsibility, the following language is recommended:

> Investments in additions or changes to Company distribution facilities required to provide this service, that is over and above the investment normally incurred to provide service to such a customer assuming the customer were to obtain its full requirements from the Company in accordance with the Rules and Regulations, will be paid by customer.

Mr. Sundermier's testimony (Tr. 1670-1671) indicates that this language more clearly sets forth PECO's policy regarding distribution facilities.

Q HAVE YOU INCLUDED IN YOUR PROPOSED RATE SCHEDULES THE RECOMMENDED LANGUAGE REGARDING PARALLEL OPERATION AND DISTRIBUTION FACILITY COST?

A Yes, I have. I have also included in my proposed rate schedules language which more clearly states the PECO policy, expressed by Mr. Sundermier during the hearing (Tr. 1628-29), that supplementary power, back-up power, and maintenance power is available to all cogenerators regardless of qualifying status under PURPA. (As with the other policies discussed above, PECO's policy on the availability of this service is not embodied in any other written document available to prospective cogenerators.)

Q ARE THERE CERTAIN PECO POLICIES SET FORTH IN THE AUXILIARY SERVICE RIDER WHICH, IF ALLOWED TO CONTINUE, CAN DISCOURAGE THE DEVELOPMENT OF QUALIFYING FACILITIES?

A Yes, there are. Foremost among such policies is PECO's stated refusal to supply supplementary power, back-up power or maintenance power to a customer receiving power from an on-site cogeneration facility not owned by that customer.

Such a policy can be especially onerous to a PECO customer, such as the hospital discussed by Mr. Sundermier (Tr. 1629-1632), that is attempting to minimize operating costs so that it can continue to provide a service and maintain employment in the state of Pennsylvania. Moreover, once the cogeneration unit is operating, from a PECO cost, operations or rate standpoint, there is no

difference between supplying a customer that owns generation facilities and a customer that does not own such facilities. Unless PECO is informed of the different ownership, it could not distinguish between the two facilities from a service perspective.

Q WHAT DO YOU RECOMMEND?

A I urge the Commission to prohibit this practice by adopting the following language regarding the availability of supplementary, back-up and maintenance power:

> Availability.
> To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

Q DOES THE AUXILIARY SERVICE RIDER HAVE A CONTROL OF SUPPLY PROVISION?

A Yes, it does. The tariff language is as follows:

> In case the number of kilowatts contracted for is less than customer's maximum demand as estimated by the Company, the Company may require the customer to limit his demand to the load in kilowatts contracted for by means of a circuit breaker or fuses, of types provided by the Company, to be furnished, installed, connected and maintained by the customer at his expense. The fuse size or the setting of the circuit breaker and its adjustment shall be under the sole control of the Company.

Q DO THE OTHER SERVICE RATE SCHEDULES OF PECO CONTAIN A CONTROL OF SUPPLY PROVISION AS SET FORTH IN THE AUXILIARY SERVICE RIDER?

A According to Company testimony, they do not. This provision is

unique to the service provided to cogenerators.

Q GIVEN THE AMOUNT OF POWER AVAILABLE TO PECO, IS IT LOGICAL THAT PECO SHOULD NEED OR DESIRE TO LIMIT SALES?

A No, it is not. Nevertheless, PECO has included such a provision in the Auxiliary Service Rider. This provision permits PECO, at its discretion, physically to limit the amount of power a supplementary power customer can purchase whereas a total requirements customer has no such limitation. Such a provision is discriminatory, may discourage cogeneration and should be eliminated.

Q WHAT IS AN APPROPRIATE WAY TO HANDLE POWER CONSUMPTION IN EXCESS OF CONTRACT AMOUNTS?

A An appropriate way to handle this situation is through an adjustment of the contract amount as described by Mr. Sundermier (Tr. 1633).

The back-up power rate which I have proposed contains such a provision for adjusting the contract in the case of electrical power consumption in excess of contract amounts.

Q CAN A CUSTOMER PURCHASE MAINTENANCE POWER ON A FIRM BASIS UNDER THE PROVISION OF THE EFFECTIVE AUXILIARY SERVICE RIDER?

A No. Maintenance power is only available on a non-firm basis. The rider clearly states that maintenance power will be subject to interruption at the sole discretion of the Company.

Q ARE THE MAINTENANCE POWER PROVISIONS OF THE EFFECTIVE AUXILIARY SERVICE RIDER CONSISTENT WITH THE FERC REGULATIONS?

A No, they are not. The FERC and PUC regulations require that maintenance power be available on a firm basis.

Q HAVE YOU ANY INDICATION THAT PECO IS WILLING TO PROVIDE MAINTENANCE POWER ON A FIRM BASIS?

A Yes, the Revised Rider indicates such a willingness. Schedule 2 of Exhibit JAR-1 ( ) presents the revised version of the Auxiliary Service Rider filed by PECO on December 27, 1985 with this Commission. The Firm Supply provision shown in Schedule 2 clearly indicates that PECO is proposing to provide maintenance power on a firm basis.

Further, the Revised Rider eliminates the 1,000 kW minimum capacity requirement and the limitations on the duration and frequency of maintenance power presently in effect.

Q DO YOU CONCUR THAT MAINTENANCE POWER SHOULD BE PROVIDED ON A FIRM BASIS AND WITHOUT THE LIMITATIONS SPECIFIED IN THE PRESENT AUXILIARY SERVICE RIDER?

A Yes, I do. My recommendations set forth in this testimony address the appropriate provisions of both firm and interruptible maintenance power.

Q HAVE YOU REVIEWED THE LIABILITY SECTION OF THE AUXILIARY SERVICE

RIDER?

A Yes, I have. The current liability provision reads as follows:

> LIABILITY. The Customer shall reimburse or hold harmless the Company for all losses to Company, Customer or third parties; for all damage to Company or Customer facilities; or for all liabilities to third parties as a result of Customer's operation or use of non-Company owned generating facilities under the provisions of this rider.

The Revised Rider filed on December 27, 1985 (Scott Exh. 1) reads somewhat differently:

> LIABILITY. The Customer shall hold the Company harmless from all losses and damages to the Customer. The Customer shall reimburse the Company or third parties for all losses and damages to the Company or third parties resulting from the Customer's operation or use of non-Company owned generating facilities under the provisions of this rider.

While the precise language differs in some respects between the two riders, several features seem to be common to both. First, there is no reference in either to liability on the part of the Company. Second, there is no expressed statement in either that indicates that the Customer's liability is limited to instances in which it is at fault.

Q DO YOU HAVE ANY COMMENTS ON THE LIABILITY PROVISION?

A I believe that the liability sections should be subject to the same general standards that guide the Commission in reviewing other terms and conditions set forth in the Auxiliary Service Rider. As I have previously mentioned, this includes the requirement that the tariff be non-discriminatory.

Q ARE THE FULL REQUIREMENTS RETAIL CUSTOMERS SUBJECTED TO THE SAME LIABILITY PROVISIONS?

A According to Mr. Sundermier, no. (Tr. 1647)

Q IS THE LIABILITY PROVISION CONSISTENT WITH THE LIABILITY PROVISIONS IN PECO INTERCHANGE AGREEMENTS WITH OTHER UTILITY SYSTEMS OPERATING IN PARALLEL WITH THE PECO SYSTEM?

A Based on the Company's response to Occidental's data request, the answer is no. Occidental asked the Company to furnish copies of all interchange agreements (IR-CHEM 44). These agreements govern transactions between PECO and companies which operate generation equipment in parallel with PECO. PECO can sell power to or purchase power from these entities. Similar arrangements for parallel operation and purchase and sale of power are common between utilities and cogenerators. I have reviewed each of these interchange agreements furnished by PECO. The liability provisions in these agreements are quite different from those contained in the rider. For instance, such agreements provide for liability by both the Company and the other parties to the Agreement.

Q WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE INCLUSION OF A LIABILITY PROVISION IN THE PECO TARIFF?

A I recommend that the Commission review the liability provision in the rider to determine whether it imposes discriminatory or excessive risks on cogenerators. If similar liability requirements are

not imposed on others who operate in parallel with PECO, the current provisions should be deleted and replaced by an even-handed provision. Such a provision could read as follows:

> Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such party's negligent operation or use of electrical facilities used in connection with the provisions of this service.

Rates for Service

Q DO YOU AGREE WITH THE PECO POSITION THAT THE NORMAL SERVICE RATE AND APPLICABLE RIDERS IS AN APPROPRIATE BASIS FOR PRICING SUPPLEMENTARY AND BACK-UP POWER?

A To supplementary power, yes, but not to back-up power. Supplementary power should be billed in accordance with the PECO service schedule and applicable riders for which the service would otherwise be available to a customer not receiving a portion of its electrical requirements from cogeneration, because supplementary power is used to meet requirements in addition to those that can be supplied from cogeneration facilities. Thus, usage by supplementary power customers is akin to normal firm rate service.

For reasons discussed later, back-up power customers can be expected to impose different costs on the system than full requirements customers. Thus, rates for back-up service should not be identical to the rates applicable to full requirements customers.

Finally, it is not appropriate to bill supplementary power in combination with back-up power as required by the PECO Auxiliary Service Rider (and the Revised Rider). These types of service are distinct and have totally different load and cost characteristics. Thus, as I will discuss later, the PECO provision that requires the combining of back-up service with supplementary service for bill purposes, is inappropriate.

Q YOU STATED EARLIER IN YOUR TESTIMONY THAT BACK-UP POWER IS BASED UPON THE PRINCIPLE THAT THE UTILITY IS PROVIDING RESERVE CAPACITY, IS THIS "RESERVE" PRINCIPLE CONSISTENT WITH HOW A UTILITY PROVIDES SERVICE TO ITS REGULAR FIRM CUSTOMERS?

A Yes, it is. For example, a utility with 3,000 MW of firm load and a 25% reserve margin requirement would install 3,750 MW of capacity. Mr. Sundermier stated that this is precisely how PECO provides to service its firm customers (Tr. 1640). Thus, a nongenerating firm customer with a load of 100 kW would pay the utility for 125 kW of capacity (100 kW associated with the load and 25 KW associated with the reserve).

Similarly, a 100 kW customer supplied by a cogeneration facility of 100 kW should only pay the utility for the reserve capacity, because the cogeneration facility is providing the 100 kW of capacity to serve the customer's load. The utility is merely responsible for the 25 MW reserve. However, both are entitled to call upon this reserve whenever needed.

Q IS THE LEVEL OF RESERVE A FUNCTION OF GENERATING RESOURCE RELIABILITY?

A Yes, it is. This means that cogeneration with reliability greater than utility-controlled resources may require reserves lower than the utility average. In fact, the PJM Pool specifically recognizes the relationship between resource reliability and reserve requirement. A PJM member having more reliable capacity has a smaller Pool obligation, all other things being equal. In the long-run, the level of necessary reserve for cogeneration can be determined by the observed performance of the cogeneration facilities.

Q DO BACK-UP SERVICE AND MAINTENANCE SERVICE IMPOSE THE SAME COSTS ON THE UTILITY?

A No, they do not. Back-up service and maintenance service are two distinct types of service which differ from regular utility service and from one another. It is important that the rates reflect this cost differential. Further, in the interest of encouraging qualifying facility (QF) development, these services should be provided in the most flexible manner possible.

The rates for back-up service should reflect the probability that back-up power will or will not contribute to the need for and the use of utility capacity. Maintenance service rates (for maintenance scheduled with the utility) should reflect the off-peak nature of this service.

Q HOW IS BACK-UP SERVICE PRICED WITH THE THE PECO AUXILIARY SERVICE RIDER?

A The PECO Auxiliary Service Rider requires a customer (including customers who are qualifying facilities) to pay for back-up service under the provisions of the "normal service rate and applicable riders."

However, the FERC requirements are that:

> A qualifying facility is entitled to purchase back-up or standby power at a nondiscriminatory rate which reflects the probability that the qualifying facility will or will not contribute to the need for and the use of utility capacity. (Section-by-section analysis of Section 292.305).

Thus, an important question is whether the "normal service rate" is appropriate, given the characteristics of back-up service.

Q HAVE YOU REVIEWED THE ANALYSES PECO PERFORMED TO DEMONSTRATE THAT THE AUXILIARY SERVICE RIDER REFLECTS THE PROBABILITY THAT BACK-UP SERVICE WILL OR WILL NOT CONTRIBUTE TO THE NEED FOR AND THE USE OF UTILITY CAPACITY?

A No, I have not made such a review because PECO did not perform any analyses. PECO has stated, in response to data requests and in testimony, that such analyses were not performed. Occidental Chemical Exhibit No. 1 is a copy of the PECO response to data requests inquiring about such analyses. Further, Mr. Sundermier testified that PECO did not develop separate load characteristics data for the services provided under the Auxiliary Service Rider

(Tr. 1679).

Thus, it is clear that the Auxiliary Service Rider is not based upon an analysis which supports that the rate for back-up service is consistent with the FERC and PUC rules and regulations.

Q IN GENERAL, HOW ARE THE MONTHLY BACK-UP SERVICE CHARGES COMPUTED UNDER PECO'S AUXILIARY SERVICE RIDER?

A The Rider states that the monthly billing for back-up power will be under the provisions of the normal service rate and applicable riders for full requirement customers.

For example, a 10,000 kW demand measured customer taking service on the currently-effective Rate HT would pay approximately $61,090 in monthly charges if the facility was forced out of service and required back-up power for 10 hours in a given summer month (10,000 x 10 x .0739 + 10,000 x 5.37 = $61,090). The same customer would pay approximately $42,960 a month during the period of October through May if he did not use any additional back-up power due to the ratchet provision of Rate HT (10,000 x .8 x 5.37 = 42,960).

Q IS THE SERVICE RIDER CONCEPT, AS IMPLEMENTED BY PECO'S AUXILIARY SERVICE RIDER, APPROPRIATE FOR DETERMINING BACK-UP SERVICE CHARGES?

A No, it is not. The rates applied to back-up power customers under the Auxiliary Service Rider (and the Revised Rider) are developed

using the characteristics of customers who are predominantly full requirement customers of PECO. There is a fundamental difference in the cost characteristics of a back-up customer and the cost characteristics of the majority of the customers who form the basis for the normal service rates.

For full requirement customers, PECO must install the capacity to supply the customer load plus the reserve capacity needed to assure that the load is reliably served. On the other hand, the cogeneration facility is supplying the load carrying capacity of a back-up power customer and PECO is only responsible for the reserve capacity. To apply the "normal service rate and applicable riders" as prescribed by the PECO Auxiliary Service Riders is to ignore the capacity supplied by the cogeneration facility.

The effect of the back-up power provisions in both PECO Riders is to assess excessive charges for back-up power and to potentially discourage cogeneration development.

Q UNDER WHAT CONDITIONS COULD THE COST CHARACTERISTICS OF BACK-UP POWER CUSTOMERS CORRESPOND TO THE COST CHARACTERISTICS OF FULL REQUIREMENTS CUSTOMERS ON THE PECO SYSTEM?

A This could occur if the electric output of all generating equipment supplying partial requirement customers sustained outages simultaneous with PECO peaks. This assumption, unless supported by factual data, is clearly prohibited by both the FERC rules and the Pennsylvania Public Utility Commission rules implementing

PURPA.

Q PLEASE ILLUSTRATE THE SIMULTANEOUS OUTAGE ASSUMPTION FOR COGENERATORS INHERENT IN THE PECO AUXILIARY SERVICE RIDER.

A This inherent simultaneous outage assumption in both the Auxiliary Service Rider and the Revised Rider is illustrated in Schedule 3 of Exhibit JAR-1 ( ). The three customers shown in Schedule 3 are assumed to be full requirement customers with cost responsibility of 10% as shown on Line 9.

Schedule 3 shows these same customers assuming they have installed cogeneration facilities and are purchasing back-up power (with equipment outages occurring on a random basis), Lines 10 through 16. The cost responsibility under the random outage scenario is about 2% (Line 17).

Obviously, a rate designed to recover the cost of full requirement customers is not appropriate for cogenerators because of the difference in the cost to provide service (compared Line 9 to Line 17). The application of a normal service rate to back-up power inherently ignores the cogeneration capacity and thus assumes simultaneous outages on the cogeneration facilities at time of peak. This is illustrated on Schedule 3, where the back-up power customer cost responsibility (10%) is identical to that of the full requirements customers (10%) (Lines 18 through 24).

Q ASIDE FROM THE INAPPROPRIATENESS OF THE RATES, CAN THE

AUXILIARY SERVICE RIDER RESULT IN SIGNIFICANTLY DIFFERENT BACK-UP POWER CHARGES TO CUSTOMERS REQUIRING THE SAME AMOUNT OF BACK-UP POWER?

A Yes, it can. In effect, a customer requiring both supplementary and back-up power can be penalized vis-a-vis a customer taking the same amount of back-up power on a stand-alone basis.

Q WOULD YOU PLEASE ILLUSTRATE HOW THIS CAN OCCUR?

A Schedule 4 of Exhibit JAR-1 ( ) illustrates the difference in back-up power charges that can result from the Auxiliary Service Rider billing provisions. In the example, one customer purchases only back-up power. Another customer purchases the identical amount of back-up power in conjunction with supplementary power. As shown in Schedule 4, the customer purchasing back-up power on a stand-alone basis pays $80,304 (Line 13). By contrast, the customer (who normally purchase $354,734 of monthly supplementary power as shown on Line 10) pays $148,686 for the same back-up power merely because supplementary power is also taken. This represents over a 85% difference in charges for the identical service. This illustration clearly shows that the Auxiliary Service Rider produces inappropriate and unreasonable charges for back-up power.

Alternate Rate Proposal for Back-Up Service and Maintenance Service

Q IN YOUR OPINION, WHAT SHOULD BE THE BASIS FOR BACK-UP SERVICE AND

MAINTENANCE SERVICE CHARGES?

A Fundamentally, cost of service should be the basis for determining the rates for back-up service and maintenance service. Although factors, such as simplicity and ease of administration may also be appropriately considered, the fundamental starting point and guideline should be that of the cost of providing service.

Q HAVE YOU DEVELOPED A PROPOSED BACK-UP SERVICE RATE THAT RECOGNIZES THE RELATIONSHIP BETWEEN COST AND COGENERATION UNIT RELIABILITY?

A Yes, I have.

Q PLEASE BRIEFLY DESCRIBE YOUR PROPOSAL.

A Under my proposed for back-up service, a customer would be obligated to pay PECO a minimum monthly payment directly related to the cost of PECO-owned production and transmission plant. When back-up service is actually taken by a cogenerator, the charges paid to PECO would be based on a proration of the service rate which would otherwise be applicable.

Q HOW DOES YOUR PROPOSAL REFLECT DIFFERENT RESERVE COSTS FOR DIFFERENT NON-UTILITY GENERATING UNIT RELIABILITIES.

A Whenever a customer takes back-up service, the monthly demand charge (of the otherwise applicable firm rate) would be applied on a prorated basis. The more back-up service required by a customer, the higher the back-up service payment. This would reflect

the higher probability that the back-up power will be taken coincident with the PECO system peaks.

Another important feature is that, while other ratepayers are protected for subsidizing a back-up power customer, this customer would never pay more than the rate this Commission has deemed appropriate for a regular firm customer of PECO. This is a much more reasonable rate for back-up service than the PECO Auxiliary Service Rider, which does not even attempt to reflect the unique characteristics of back-up service (and can also charge vastly different amounts for the same service).

Q WHAT ARE YOU PROPOSING AS THE APPROPRIATE RATE FOR ESTABLISHING THE MINIMUM BACK-UP SERVICE PAYMENT?

A A monthly rate of $3.35 per kilowatt based on PECO's full requested revenue level. (If the approved rate level is less than requested, this charge should be appropriately reduced to reflect the approved rate level.)

Q HOW WAS THE $3.35 PER KILOWATT DEMAND CHARGE DEVELOPED?

A Schedule 5 of Exhibit JAR-1 ( ) shows the development of the $3.35 per kilowatt demand charge. This charge represents the monthly cost associated with the reserve component of PECO's production and transmission plant. Column 1 of Schedule 5 shows the total plant in-service investment (Line 3), the total accumulated depreciation (Line 6), and the net plant associated with

production and transmission plant (Line 7). Column 2 shows the annual cost (based on Company-sponsored Exhibits in this docket) associated with the requested return on plant, depreciation expense, and income taxes. Line 11 shows that the total annual cost of these elements is approximately $1,435 million. Column 3 shows that the per-unit cost associated with production and transmission plant on a $/kW of total installed capability basis. Line 13 of Schedule 5 shows the annual reserve cost for production and transmission at a 22% planning reserve margin. Line 17 shows the development of the monthly minimum cost of $3.35/kW.

Q UNDER YOUR PROPOSAL, WHAT WOULD BE THE MINIMUM MONTHLY PAYMENT FOR A CUSTOMER WHO CONTRACTS FOR 10,000 KILOWATTS OF BACK-UP SERVICE?

A A customer who contracts for 10,000 kW of back-up service would be obligated to make a minimum monthly payment of $33,500 per month (10,000 x 3.35 = 33,500). Of course, when the back-up power is actually taken, the total payment would be a function of the amount of back-up service taken. But in no event, would the payment made by a customer in any month be less than the $33,500 figure. Furthermore, a customer would be obligated to enter into a contract with PECO for back-up service covering not less than 12 calendar months. This would result in a minimum annual payment of $402,000. Note that this is approximately $100,000 more than the 40% minimum contract demand payment requirement of Rate HT (9.44 x 10,000 x .4 x 8 = 302,080).

Q WOULD THE $33,500 FIGURE IN YOUR PREVIOUS EXAMPLE BE IN ADDITION TO THE CHARGES COMPUTED FOR BACK-UP SERVICE ACTUALLY TAKEN DURING A MONTH?

A No. The $33,500 represents a minimum monthly payment and is not an additional charge. For example, in a month when the charge for actual service taken was $20,000, a customer would pay $33,500. However, in a month when the actual charges were $46,000, the customer would pay $46,000.

Q IN YOUR OPINION, SHOULD THE UTILITY BE COMPENSATED DIFFERENTLY FOR BACK-UP POWER DELIVERED IN EXCESS OF THE BACK-UP CONTRACT CAPACITY?

A Yes. I recommend that the utility be compensated for the excess power at the service rate set forth in the back-up power contract <u>without</u> proration for that month. In other words, the excess power delivered by the utility would be priced at the full monthly firm rate for the initial month. Furthermore, the Back-Up Contract Capacity should be increased to the "delivered" amount for the ensuing 12 months.

Q SHOULD THE CUSTOMER BE ALLOWED TO REDUCE THE REVISED BACK-UP CONTRACT CAPACITY AT THE END OF THE 12-MONTH PERIOD?

A Yes. However, I believe this is best left to negotiation.

Q DO YOU HAVE AN ALTERNATE PROPOSAL REGARDING MAINTENANCE SERVICE?

A Yes, I do.

Q HOW DOES YOUR ALTERNATE PROPOSAL FOR MAINTENANCE SERVICE DIFFER FROM THAT OF PECO'S?

A With regard to the effective Auxiliary Service Rider, my proposal differs as follows:

1. Scheduled Maintenance Power under my proposal would be on a firm basis whereas the PECO rider only provides maintenance power on an unscheduled basis.

2. Under my proposal, Maintenance Power would be available to all customers whereas PECO's rider excludes customers with loads less than 1,000 kW.

3. The scheduling notification period under my proposal is not less than 12 calendar months, whereas the PECO rider has a notification period of at least 30 days.

4. My proposal requires the customer to notify the Company when maintenance power is no longer required whereas the PECO rider suggests that the customer can return to service without notifying the Company.

With regard to the revised rider filed on December 27, 1985, my maintenance power proposal differs in two major respects. The first area pertains to the scheduling of maintenance power. My proposal requires the customer to provide not less than 12 months written notification that maintenance power is required of the Company (PECO's notification period is 30 days). Further, maintenance power under my proposal is restricted to the off-peak period of October through May, whereas the PECO revised rider has no such restriction. The PECO revised rider requires approval from the Company for scheduled maintenance to be performed. My

proposal, with its extended notification and restricted period available for maintenance, allows the customer to select the period during which maintenance is to be performed.

The other major difference is that my proposal provides a rate which reflects the off-peak nature of maintenance service, whereas the PECO revised rider does not reflect the cost-causative nature of maintenance service and would charge an inappropriately high rate for this service.

Q BRIEFLY DESCRIBE YOUR PROPOSAL REGARDING SCHEDULED MAINTENANCE SERVICE?

A Scheduled Maintenance Service would be provided to a customer who provides PECO with not less than 12 months advance written notice that scheduled maintenance is to be performed. Further, the period during which scheduled maintenance can be performed is restricted to the off-peak period of October through May. These two factors would assure PECO that maintenance service would not contribute to system peak requirements.

As with both the effective Auxiliary Service Rider and the Revised Rider (Tr. 1662-64), my proposal is also based upon a proration of the otherwise applicable firm rate. However, my proposal for scheduled maintenance takes into account the reduced system cost associated supplying scheduled maintenance power.

Q HOW DOES PECO ALLOCATE PRODUCTION AND TRANSMISSION PLANT AND

RELATED EXPENSES TO CLASSES OF SERVICE?

A PECO allocates these costs on the basis of the average contribution of each class to hourly system peaks in each of the four summer months (June through September). As stated in Mr. Sundermier's direct prefiled testimony on Page 6 at Line 19:

> Production and transmission plant must be designed to meet the maximum demand requirements imposed on the system by the customers; therefore, it is appropriate that these costs should be allocated on the basis of contribution to those peak demands.

Q UNDER THE COMPANY'S ALLOCATION METHOD, HOW MUCH PRODUCTION AND TRANSMISSION PLANT AND RELATED EXPENSES SHOULD BE ALLOCATED TO CUSTOMERS RECEIVING SERVICE UNDER YOUR SCHEDULED MAINTENANCE PROPOSAL?

A My scheduled maintenance proposal is designed to assure PECO that additional production and transmission plant and related expenses will not be imposed upon the PECO system. Thus, to be consistent with the PECO allocation method, the scheduled maintenance service customers should not be allocated any production and transmission plant or related expenses.

Q HOW HAVE YOU REFLECTED THE REDUCED COSTS WHICH WOULD BE IMPOSED ON PECO BY CUSTOMERS RECEIVING SERVICE UNDER YOUR SCHEDULED MAINTENANCE POWER PROPOSAL?

A This cost reduction is reflected by way of a Scheduling Provision Factor of 0.05 which would be applied to the normal billing demand.

Q HOW WOULD THE BILLING DEMAND FOR SCHEDULED MAINTENANCE BE COMPUTED UNDER YOUR PROPOSAL?

A The customer scheduling his maintenance power requirements with PECO under the provisions of my scheduled maintenance service would have his normal billing demand reduced by 50%. This scheduling provision factor reflects the off-peak type of service that is being provided and the corresponding costs.

Q WHAT WOULD BE THE BILLING DEMAND FOR A CUSTOMER WHO SCHEDULED 10,000 KILOWATTS OF MAINTENANCE POWER UNDER YOUR PROPOSAL?

A Schedule 6 of Exhibit JAR-1 ( ) illustrates the calculation of the billing demand and the resulting scheduled maintenance power payment under my proposal. Line 6 shows that the billing demand would be the product of the 10,000 kW and the 0.50 scheduling provision factor. Thus the billing demand for a customer who schedules 10,000 kW of demand would be 5,000 kW.

Q DOES THE PRORATION METHOD SET FORTH IN SCHEDULE 6 OF EXHIBIT JAR-1 ( ) REFLECT THE METHOD OF PRORATION THAT WOULD APPLY TO BOTH SCHEDULED MAINTENANCE POWER AND BACK-UP POWER UNDER YOUR PROPOSAL?

A Yes, it would. The ratio of the days of power use to the days in the month would be applied to the capacity charge calculation and the hours' use blocking in the energy charge.

Q HAVE YOU PREPARED SPECIFIC RATE SCHEDULES FOR SUPPLEMENTARY POWER,

BACK-UP POWER AND MAINTENANCE POWER WHICH IMPLEMENTS YOUR RECOMMENDATIONS?

A Yes, I have. Schedule 7 of Exhibit JAR-1 ( ) is a rate schedule which incorporate my recommendations regarding supplementary power. Schedules 8 and 9 incorporate my recommendations with regard to back-up power and maintenance power, respectively.

Q IN ORDER TO RECOGNIZE THE VARYING SERVICE NEEDS AND TO ENCOURAGE THE DEVELOPMENT OF QUALIFYING FACILITIES, SHOULD BACK-UP AND MAINTENANCE SERVICE ALSO BE PROVIDED AND PRICED ON AN "AS-AVAILABLE" BASIS?

A Yes, it should. Under an "as-available" method, the customer would not pay for any monthly capacity charges. However, at the time the customer desires service, he would pay a rate based upon the additional energy charges incurred by the utility, plus a mark-up.

Although the customer would not be obligated to pay capacity payments, the utility would not be obligated to ensure that the capacity would be available at all times.

Q WHAT IS THE APPROPRIATE RATE FOR "AS-AVAILABLE" BACK-UP AND MAINTENANCE SERVICE?

A The appropriate rate for this type of service is the Company's hourly PJM billing rate plus a 10% adder. Thus, PECO would have complete control with regard to supplying the service and also

would be assured of receiving full compensation for all costs associated with power supplied.

Q IS PECO A PARTY TO AGREEMENTS THAT PROVIDE FOR TRANSACTIONS SIMILAR TO YOUR "AS-AVAILABLE" BACK-UP AND MAINTENANCE POWER PROPOSAL?

A Yes, it is. PECO is a party to a number of agreements where energy is scheduled to another party when the other party cannot supply the energy with its own resources. Further, the agreements call for the costing of such energy supplied based upon the cost of generating the energy plus an adder which ranges from $1.40 per megawatthour to $2.60 per megawatthour. Based upon the projected PJM hourly billing rates, the 10% adder that I have recommended should be more than adequate when compared to these transactions.

Q HAVE YOU PREPARED A SPECIFIC RATE SCHEDULE FOR AS-AVAILABLE POWER?

A Yes, I have. Schedule 10 of Exhibit JAR-1 ( ) is a rate schedule which would implement the as-available back-up and maintenance service proposal. Note that the $24 per kW figure appearing in the Penalty For Failure to Curtail section shown in Schedule 10 is based on PECO's full requested revenue level. Thus, if the approved rate level is less than requested, this charge should be appropriately reduced.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does. However, supplemental testimony may be necessary upon receipt of information which has been requested from PECO.

Qualifications of James A. Ross

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James A. Ross, 605 Old Ballas Road, St. Louis, Missouri.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation with the firm of Drazen-Brubaker & Associates, Inc., utility rate and economic consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I am a graduate of the University of Missouri, with the degrees of Bachelor of Science in Electrical Engineering and Master of Science in Engineering Management.

After graduation in 1971, I was employed by Union Electric Company, a utility which provides service to Metropolitan St. Louis, Missouri, and surrounding areas. While assigned to the Power Operation Function, I was responsible for system operation-related engineering evaluations which included long-range and intermediate planning studies, various economic studies and computer simulation of system operations. I was later assigned to the Corporate Planning Function with responsibilities in capacity planning coordination activities and special studies. Subsequent to my ten-year employment with Union Electric Company, I joined the firm of Drazen-Brubaker & Associates, Inc.

Q DURING YOUR EMPLOYMENT WITH UNION ELECTRIC COMPANY, DID YOU PARTICIPATE IN ANY CAPACITY PLANNING EVALUATIONS?

A Yes, I was responsible for assisting in all facets of Union Electric's ten-year capacity addition studies. My responsibilities included computer simulation of system operations, development of capacity addition strategies and engineering economic evaluation of alternatives. Additionally, I was assigned to the System Studies Group of the Compressed Air Energy Storage research project sponsored by the Department of Energy and the Electric Power Research Institute. My responsibilities included participation in the overall capacity planning evaluation of compressed air energy storage as a viable capacity alternative and authoring portions of the Project's report on utility system planning.

Also, while assigned to the Corporate Planning Function, I was assigned to a Union Electric oversight committee regarding a power plant siting study being performed by an outside consultant.

Q WHAT REGULATORY COMMISSIONS HAVE YOU TESTIFIED BEFORE?

A I have testified on electric rates and related matters before the regulatory commissions of Alabama, Colorado, Idaho, Louisiana, Massachusetts, Michigan, New York, South Carolina, Texas, Utah and Wyoming.

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Exhibit

of

JAMES A. ROSS

On behalf of

Occidental Chemical Corporation

January 1986
Project 4066

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

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SUPPLEMENT NO. 6 TO
ELECTRIC-PA. P.U.C. NO. 26
FIRST REVISED PAGE NO. 52
Superseding Original Page No. 52

Philadelphia Electric Company

STANDARD RIDERS-Continued

Applicable to rates as indicated in Applicability Index of Riders

AUXILIARY SERVICE RIDER

APPLICABILITY. Service to customers, including qualified small power production or cogeneration facilities (qualifying facilities) operating in parallel with the Company, any part of whose electric requirements are regularly provided by facilities owned by that Customer, and where the Company supply can be substituted for that of the Customer, will be supplied only under the provisions of this rider.

EXTENT OF SUPPLY. The maximum firm supply available from the Company will be defined by contract except for customers served on Rates R, R-H and GS-without demand measurement.

CONTROL OF SUPPLY. In case the number of kilowatts contracted for is less than the Customer's maximum demand as estimated by the Company, the Company may require the Customer to limit his demand to the load in kilowatts contracted for by means of a circuit breaker or fuses, of types approved by the Company, to be furnished, installed, connected and maintained by the Customer at his expense. The fuse size or the setting of the circuit breaker and its adjustment shall be under the sole control of the Company.

PARALLEL OPERATION. The Customer shall not at any instant operate any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

TYPE OF SUPPLY. The following types of power supply are available:

Back-up Power supply is available to replace the Customer's own generating capacity whenever it may be interrupted on an unscheduled basis.

Supplementary Power supply is available to add to the Customer's own generating capacity on a continuing firm supply basis.

Maintenance Power supply is available to customers whose total load exceeds 1,000 kilowatts to replace part or all of the Customer's own generating capacity. The supply of maintenance power will be on a scheduled basis that is acceptable to the Company, with at least thirty days advance written notice required, and will be subject to interruption at the sole discretion of the Company. Maintenance periods will be limited to a maximum of three months duration and two occurrences per year which must be separated by at least thirty days. The supply of maintenance power will be terminated when the Customer's generating capacity is returned to operation as indicated by the recorded demands on the Company's metering equipment or upon notification to the Company by the Customer, whichever occurs first.

RATE AND BILLING.

Back-up or Supplementary Power will be available to the Customer under a contract that will specify the total maximum capacity that the Company could be required to serve at any time. The monthly billing for Back-up or Supplementary Power will be under the provisions of the normal service rate and applicable riders. (C)

Maintenance Power will be billed under the provisions of the normal service rate, except that charges will be prorated for periods of less than one month's supply. The minimum contract demand and the summer month ratchet of the normal service rate will not be applicable. Qualifying facilities will be billed under the provisions of the night service rider corresponding to the appropriate rate schedule.

DISTRIBUTION FACILITIES. Any investment in additions or changes to Company distribution facilities required to provide back-up power, supplementary power or maintenance power will be paid by the Customer before the interconnection of Company and Customer facilities.

LIABILITY. The Customer shall reimburse or hold harmless the Company for all losses to Company, Customer, or third parties; for all damage to Company or Customer facilities; or for all liabilities to third parties as a result of Customer's operation or use of non-Company owned generating facilities under the provisions of this rider.

TERM.

Annual, except where otherwise specified by the firm rate.

(C) Indicates change.

STANDARD RIDERS-Continued

Applicable to rates as indicated in Applicability Index of Riders

AUXILIARY SERVICE RIDER (C)

APPLICABILITY. Service to those customers, including qualifying facilities of small power producers and cogenerators as defined in the Public Utility Regulatory Policies Act, operating in parallel with the Company, any part of whose electric requirements are regularly provided by facilities owned by that Customer, and where the Company supply can be substituted for that of the Customer, will be supplied only under the provisions of this rider.

EXTENT OF SUPPLY. The maximum demand requirement and, when applicable, the firm capacity demand (see Paragraph on Curtailable Supply) available from the Company will be defined by contract except for customers served on Rates R, R-H and GS-without demand measurement.

CONTROL OF SUPPLY. In case the number of kilowatts contracted for is less than the Customer's maximum demand as estimated by the Company, the Company may require the Customer to limit his demand to the load in kilowatts contracted for by means of a circuit breaker or fuses, of types approved by the Company, to be furnished, installed, connected and maintained by the Customer at his expense. The fuse size or the setting of the circuit breaker and its adjustment shall be under the sole control of the Company.

PARALLEL OPERATION. The Customer shall not at any instant operate any source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

TYPES OF AUXILIARY SERVICES. The following types of auxiliary service are available:
BACK-UP POWER supply is available to replace the energy used by the Customer whenever the Customer's own generating capacity is interrupted on an unscheduled basis.
SUPPLEMENTARY POWER supply is available to add to the Customer's own generating capacity.
MAINTENANCE POWER supply is available to replace the Customer's own generating capacity during periods of scheduled maintenance. The supply of maintenance power will be on a scheduled basis that is acceptable to the Company with at least thirty days' advance written approval from the Company required. The supply of maintenance power will be terminated when the Customer's generating capacity is returned to normal operation as indicated by the recorded demands on the Company's metering equipment or upon notification to the Company by the Customer, whichever occurs first.

FIRM SUPPLY. Auxiliary service will be billed under the provisions of the rate applicable to the voltage of the service supply from the Company and applicable riders except that charges for maintenance power will be prorated in accordance with the number of days that the service is supplied during the billing month.

DEFINITION OF PEAK HOURS. On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Saving Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the on-peak hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as on-peak hours.

(Continued)

(C) Indicates change.

Philadelphia Electric Company

SUPPLEMENT NO. 18 TO
ELECTRIC-PA. P.U.C. NO. 26
ORIGINAL PAGE NO. 52A

STANDARD RIDERS-Continued

Applicable to rates as indicated in Applicability Index of Riders

AUXILIARY SERVICE RIDER-Continued

CURTAILABLE SUPPLY. Customers may agree to curtail their demand during on-peak hours to a value specified in the contract. This demand value is the firm capacity demand required by the Customer and shall provide for a minimum of 1,000 kilowatts of curtailable demand during on-peak hours. The Customer shall reduce demand to the firm capacity value after a minimum of 30 minutes prior notice by the Company when, in the sole judgment of the Company, any capacity limitations exist. Customers with curtailable load will be billed under the provisions of the normal service rate and applicable riders except that during the eight months of October through May the billing demand will not be less than 40% of the firm capacity nor less than 80% of the highest billing demand in the preceding months of June through September, but in no case shall the minimum billing demand be greater than 80% of the firm capacity demand, except as indicated under the paragraph on Penalty For Failure to Curtail. Curtailable load will be prorated in accordance with the number of days that the maximum registered demand exceeds the firm capacity demand. There shall be a monthly transmission reservation charge of $2.16 per kilowatt of curtailable load plus, when applicable, a distribution reservation charge of $0.98 per kilowatt of curtailable load. The State Tax Adjustment Clause shall be applicable to these charges. These charges will apply in all months; however, in any month in which the Customer's on-peak billing demand exceeds the firm capacity demand, there will be a credit determined by multiplying the transmission charge and, when applicable, the distribution charge by the demand in excess of the firm capacity demand. If the Customer does not elect to reserve transmission and distribution capacity, the reservation charge will be waived; however, the Customer will be at risk for additional curtailment as a result of the unavailability of transmission and distribution capacity. If a Customer does not elect to reserve transmission and distribution capacity and subsequently wants to reserve such capacity, the Customer must pay for any additional costs that the Company incurs to provide such capacity. When a Customer elects to pay the reservation charge, the option to waive this charge will no longer be available.

PENALTY FOR FAILURE TO CURTAIL. The first time that the Customer is notified by the Company to curtail to the firm capacity demand and the Customer fails to curtail to this demand, a penalty of $24 per kilowatt shall be applicable to each kilowatt of maximum registered demand that is in excess of the Customer's firm capacity demand during the curtailment period. In addition, if the failure to curtail occurs in a summer month the minimum billing demand in the following months of October through May shall not be less than 80% of the maximum measured demand during the period in which the Customer failed to curtail. The second time that the Customer fails to curtail, the same penalty shall be applicable and curtailable supply will not be available to the Customer for a period of three years.

DISTRIBUTION FACILITIES. Any investment in additions or changes to Company distribution facilities required to provide auxiliary service will be paid by the Customer before the interconnection of Company and Customer facilities. In addition, when required by the Company, the cost of communication equipment, such as telemetering or telephone, will be paid by the Customer.

LIABILITY. The Customer shall hold the Company harmless from all losses and damages to the Customer. The Customer shall reimburse the Company or third parties for all losses and damages to the Company or third parties resulting from the Customer's operation or use of non-Company owned generating facilities under the provisions of this rider.

TERM. In accordance with the applicable rate schedule, except that customers with curtailable load shall notify the Company at least three years prior to termination of curtailable supply under the provisions of this rider.

(C) Indicates change.

Schedule 3

PHILADELPHIA ELECTRIC COMPANY

Illustration of Simultaneous Outage Assumptions
Inherent in PECO Auxiliary Service Rider

Line	Description	Jun. (MW) (1)	Jul. (MW) (2)	Aug. (MW) (3)	Sept. (MW) (4)	4-Month Average (5)	Percent of System (6)
1	System	2,000	2,000	2,000	2,000	2,000	
	Full Requirements Customers						
2	Customer 1 - Contract Capacity	100	100	100	100	100	
3	Coincident Peak Demand	80	80	80	80	80	
4	Customer 2 - Contract Capacity	50	50	50	50	50	
5	Coincident Peak Demand	40	40	40	40	40	
6	Customer 3 - Contract Capacity	100	100	100	100	100	
7	Coincident Peak Demand	80	80	80	80	80	
8	Total Contribution to System Peak	200	200	200	200	200	
9	Full Requirements Customer Cost Responsibility as a Percent of System Peak						10%
	Backup Power Customers with Random Outages						
10	Customer 1 - Contract Capacity	100	100	100	100	100	
11	Coincident Peak Demand	0	0	0	0	0	
12	Customer 2 - Contract Capacity	50	50	50	50	50	
13	Coincident Peak Demand	50	0	0	50	25	
14	Customer 3 - Contract Capacity	100	100	100	100	100	
15	Coincident Peak Demand	0	0	80	0	20	
16	Total Contribution to System Peak	50	0	80	50	45	
17	Backup Power Customer Cost Responsibility as a Percent of System Peak						2%
	Backup Power Customers with Simultaneous Outages at Time of Peak						
18	Customer 1 - Contract Capacity	100	100	100	100	100	
19	Coincident Peak Demand	80	80	80	80	80	
20	Customer 2 - Contract Capacity	50	50	50	50	50	
21	Coincident Peak Demand	40	40	40	40	40	
22	Customer 3 - Contract Capacity	100	100	100	100	100	
23	Coincident Peak Demand	80	80	80	80	80	
24	Total Contribution to System Peak	200	200	200	200	200	
25	Backup Power Customer Cost Responsibility as a Percent of System Peak						10%

PHILADELPHIA ELECTRIC COMPANY

Illustration of Inconsistent Backup Power
Billing on PECO
Auxiliary Service Rider

Line	Description	Amount
	Supplementary Power Monthly Requirements:	
1	Billing Demand - kW	10,000
2	Energy Use - kWh	5,840,000
	Backup Power Monthly Requirements:	
3	Billing Demand - kW	10,000
4	Energy Use - kWh	360,000
	Rate HT Base Rate Power Cost (Excluding TOU Adjustment)	
	Supplementary Power:	
5	Capacity Charge (10,000 @ 5.37)	$ 53,700
	Energy Charge:	
6	First 150 Hours' Use (1,500,000 @ .0739)	110,850
7	Next 150 Hours' Use (1,500,000 @ .0556)	83,400
8	All Additional kWh (2,840,000 @ .0376)	106,784
9	Total Energy Charge	301,034
10	Total (Line 5 + Line 9)	$ 354,734
	Backup Power	
11	Capacity Charge (10,000 @ 5.37)	$ 53,700
12	Energy Charge (360,000 @ .0739)	26,604
13	Total	$ 80,304
	Charges for Supplementary Power and Backup	
14	Power (Line 10 + Line 13)	$435,038
	Auxiliary Service Rider Combined Billing	
15	Capacity Charge (20,000 kW @ 5.37)	$107,400
	Energy Charge:	
16	First 150 Hours' Use (3,000,000 @ .0739)	221,700
17	Next 150 Hours' Use (3,000,000 @ .0556)	166,800
18	All Additional kWh (200,000 @ .0376)	7,520
19	Total Energy Charge	396,020
20	Total (Line 15 + Line 19)	503,420
	Total Backup Power Charges Under Auxiliary Service Rider Provision	
21	(Line 20 - Line 10)	$148,686
	Increase in Backup Charge Due to Combined Billing Provision Assuming No Change in Supplementary Charge (Percent Line 21	
22	Exceeds Line 13)	85.2%

PHILADELPHIA ELECTRIC COMPANY

Development of
Minimum Monthly Backup Contract Capacity Rate

Line	Description	Plant Investment (000) (1)	Annual Cost (000) (2)	Per Unit Cost ($/kW) (3)
	Plant in Service			
1	Production	$6,585,483		
2	Transmission	636,683		
3	Total	7,222,166		
	Less: Accumulated Depreciation			
4	Production	900,583		
5	Transmission	195,169		
6	Total	$1,095,752		
7	Net Plant (Line 3 - Line 6)	$6,126,414		
8	Return on Total @ 12.70%		$ 778,055	
	Production and Transmission			
9	Depreciation Expense		222,362	
10	Income Taxes		434,155	
11	Total Annual Cost		$1,434,572	
	Per Unit Cost @ 7,858,000 kW			
12	of Installed Capability			$182.56
13	Annual Reserve Cost @ 22%			$ 40.16
	Monthly Minimum Cost			
14	(Line 13 ÷ 12)			$ 3.35

Sources: Company Exhibit WFS-1 and PECO Statement No. 14.

PHILADELPHIA ELECTRIC COMPANY

Illustration of
Proposed Scheduled Maintenance Charges

Line	Description	Amount
	Maintenance Power Requirement	
1	Days in Month	30
2	Days of Power Use	15
3	Measured Demand - kW	10,000
4	Energy Use - kWh	2,880,000
5	Scheduling Provision Factor	0.50
	Determination of Billing Demand	
6	kW of Billing Demand (10,000 x 0.50)	5,000
	Proration of Rate HT To Calculate Monthly Charge	
7	Capacity Charge (5,000 x (15/30) x 5.73)	$ 14,325.00
	Energy Charge	
	First 150 Hours' Use:	
8	(5,000 x 150 x (15/30) x .0739)	27,712.50
	Next 150 Hours Use:	
9	(5,000 x 150 x (15/30) x .0556)	20,850.00
	All Additional kWh:	
10	(2,130,000 @ .0376)	80,088.00
11	Total Energy Charge	128,650.50
12	Total Scheduled Maintenance Power Payment	$142,975.50

PHILADELPHIA ELECTRIC COMPANY

Rate SP - Supplementary Power

Availability.

To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

Conditions of Supply.

The maximum firm supply available from the Company will be defined by contract except for customers served on Rates R, R-H and GS--without demand measurement. Supplementary Power is available to add to the generating capacity from facilities other than those of the Company that regularly provide a part of customer's electrical requirements.

Parallel Operation.

The Customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

Rate and Billing.

The monthly billing for Supplementary Power will be under the provision of the service rate and applicable riders identified in the Contract.

Liability.

Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such party's negilgent operation or use of electrical facilities used in connection with the provisions of this service.

Term.

Annual, except where otherwise specified by the firm rate.

PHILADELPHIA ELECTRIC COMPANY

Rate BP - Back-Up Power

Availability.

To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

Conditions of Supply.

The maximum supply to be made available from the Company will be defined by contract (hereinafter referred to as "Back-Up Contact Capacity). Back-up power is available to replace generating capacity from facilities other than those of the Company, whenever such capacity may be interrupted on an unscheduled basis.

Parallel Operation.

The Customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned outages subsequent to the initial parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

Rate and Billing.

The monthly billing for the Back-up Power will be in accordance with the Monthly Rate Table including applicable adjustments of the service rate identified in the Contract, except that the capacity and energy charge shall be prorated on a daily basis for periods of less than one month's supply. The minimum contract demand and summer month ratchet of the normal service rate will not be applicable nor will the minimum charge.

Determination of Billing Demand.

The billing demand will be the maximum measured demand, adjusted for power factor in accordance with the Rules and Regulations, occurring during any unscheduled outage period of the month less the Supplementary Power billing demand; less the Scheduled Maintenance Power Capacity for the month if one or both of these additional services are provided at the time of the maximum measured demand.

Minimum Charge.

The monthly minimum charge shall be the customer charge of the service rate identified in the Contract, plus $3.35 per kW of Back-Up Contract Capacity.

Distribution Facilities.

Investments in additions or changes to Company distribution facilities required to provide this service, that is over and above the investment normally incurred to provide service to such a customer assuming the customer were to obtain its full requirements from the Company in accordance with the Rules and Regulations, will be paid by customer.

Excess Supply.

Back-up power billing demand in excess of Back-Up Contract Capacity will be billed in accordance with Rate and Billing provision of this Rate BP without proration. The Back-Up Contract Capacity shall be increased to the level established by measurement and the contract term extended for the ensuing 12 calendar months.

Liability.

Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such party's negilgent operation or use of electrical facilities used in connection with the provisions of this service.

Term of the Contract.

Annual, continuing thereafter unless cancelled upon 12 months' prior notice.

PHILADELPHIA ELECTRIC COMPANY

Rate SMP - Scheduled Maintenance Power

Availability.

To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

Conditions of Supply.

The maximum supply to be made available from the Company will be defined by contract. Scheduled Maintenance Power is available to replace generating capacity from facilities other than those of the Company, whenever such capacity is scheduled out of service during the period October through May, on not less than 12 months advanced written notice. The supply of Scheduled Maintenance Power shall be terminated upon notification to the Company by the Customer.

Parallel Operation.

The Customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

Rate and Billing.

The monthly billing for the Scheduled Maintenance Power will be in accordance with the Monthly Rate Table including applicable adjustments of the service rate identified in the Contract, except that the capacity and energy charge shall be prorated on a daily basis for periods of less than one month's supply. The minimum contract demand and summer month ratchet of the normal service rate will not be applicable nor will the minimum charge.

Determination of Billing Demand.

The billing demand will be the product of the amount of capacity scheduled with the Company, adjusted for power factor, and the Scheduling Provision Factor of 0.50.

Minimum Charge.

The monthly minimum charge shall be the customer charge of the service rate identified in the Contract.

Distribution Facilities.

Investments in additions or changes to Company distribution facilities required to provide this service, that is over and above the investment normally incurred to provide service to such a customer assuming the customer were to obtain its full requirements from the Company in accordance with the Rules and Regulations, will be paid by customer.

Liability.

Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such party's negilgent operation or use of electrical facilities used in connection with the provisions of this service.

Term.

Annual, continuing thereafter unless cancelled upon 12 months' prior notice.

PHILADELPHIA ELECTRIC COMPANY

Rate AP - As-Available Power

Availability.

To any customer whose electrical requirements or any part thereof are regularly provided by facilities other than those of the Company, including qualified small power production or cogeneration facilities (qualifying facilities).

Parallel Operation.

The Customer shall not begin initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not required for re-establishing parallel operation occasioned by outages subsequent to the initial parallel operation. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

Conditions of Supply.

The load supplied by this service must be completely interruptible on notice of at least one-half hour when, in the sole judgment of the Company, any capacity limitations exist. As-Available Power is available to replace generating capacity from facilities other than those of the Company, whenever such capacity is out of service.

Rate and Billing.

Service will be billed at the Company's hourly PJM Billing Rate, plus 10% of that hourly rate. The measured demand of the load supplied by this service will not be included in the calculation of billing demand for other service provided by Company. The PJM dispatch rate will be made available to the Customer on request, in order to estimate the Company's PJM Billing Rate. If the Customer fails to Interrupt the load at the time designated by the Company, the Penalty for Failure to Curtail will be applicable for the monthly billing without modification.

The Energy Cost Rate, State Tax Adjustment and Rate HT Time-of-Use Adjustment are not applicable to this service.

Penalty for Failure to Curtail.

The first time that the Customer is notified by the Company to curtail the Customer fails to curtail a penalty of $24 per kilowatt shall be applicable to each kilowatt of maximum registered demand that is associated with its service during the curtailment period. In addition, if the failure to curtail occurs in a summer month the minimum billing demand in the following months of October through May shall not be less than 80% of the demand during the period in which the Customer failed to curtail. The second time that the Customer fails to curtail within a 12 calendar-month period, the same penalty shall be applicable and curtailable supply will not be available to the Customer for a period of one year.

Liability.

Each party shall reimburse or hold harmless the other for all losses to the other party or third parties; for all damage to the facilities of the other party; or for all liabilities to third parties as a result of such party's negilgent operation or use of electrical facilities used in connection with the provisions of this service.

Minimum Charge.

The monthly minimum charge shall be the customer charge of the service rate identified in the Contract.

Term.

Annual, continuing thereafter unless cancelled upon 12 months' prior notice.