OCA STATEMENT NO. 8

2-21-86

Phila, PA

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

DOCKET NUMBER R-850152

DIRECT TESTIMONY AND EXHIBITS OF

BRUCE R. OLIVER

TESTIMONY ON
COST-OF-SERVICE AND RATE STRUCTURE ISSUES

ON BEHALF OF
THE OFFICE OF CONSUMER ADVOCATE

JANUARY, 1986

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Bruce R. Oliver. My business address is 1309 Juliana Place, Alexandria, Virginia.

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

A. I am President of Revilo Hill Associates, Inc., and I am responsible for the firm's consulting activities in the areas of utility rates and regulatory policy.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been requested by the Office of Consumer Advocate to address cost-of-service and rate structure issues in the filing of the Philadelphia Electric Company (hereinafter referred to as "PECO" or the "Company") in this proceeding. This testimony responds to positions presented by witnesses Williams and Sundermeir for the Company.

Q. PLEASE SUMMARIZE YOUR EXPERIENCE AND QUALIFICATIONS.

A. I am an economist specializing in energy and utility regulation. I have over 12 years experience in energy and utility policy issues. That experience includes service in managerial positions in the rate departments of two major utilities, the Pacific Gas & Electric Company and the Potomac Electric Power Company, as well as service in management and senior staff positions in three consulting firms, Revilo Hill Associates, Inc., the Resource Dynamics Corporation and ICF Incorporated. As a consultant I have served a diverse group of clients on issues encompassing a wide range of utility related activities. My clients have included state regulatory commissions, utilities, state-funded consumer advocacy agencies, federal agencies, major commercial and industrial users of utility services, suppliers of equipment and services to utility markets, residential consumer intervenors, the Electric Power Research Institute and the World Bank. Projects for those clients have included work on gas, electric, telephone, and water utility rate cases, as well as analyses and forecasts of supply, demand and prices for various utility and non-utility markets. I have submitted testimony in regulatory proceedings addressing such issues as costs of service, rate design, load research, load management, and metering.

To date I have testified before utility regulatory commissions in ten jurisdictions. Those jurisdictions include: New Jersey, Pennsylvania, Maryland, Virginia, North Carolina, Ohio, South Dakota, California, the District of Columbia, and the City of Philadelphia. I have personally prepared and directed the preparation of embedded, marginal, and avoided cost-of-service studies. I have designed rates for all types and classes of utility customers, and I have lectured and given presentations on such topics as marginal cost pricing and rate design design, load management, and cogeneration. I hold both bachelors and masters degrees in economics from Virginia Polytechnic Institute and State University. A copy of my resume is attached as Appendix A.

Q. HAVE YOU PREVIOUSLY APPEARED BEFORE THIS COMMISSION?

A. Yes, I have appeared before this Commission in the following electric, gas, and water utility proceedings:

Philadelphia Electric Company	Docket No. R-811626
Pennsylvania Gas and Water Company	
Gas Division	Docket No. R-821961
Water Division	Docket No. R-822102
Pennsylvania Power and Light Company	Docket No. R-822169
Metropolitan Edison Company	Docket No. R-822249
Pennsylvania Electric Company	Docket No. R-822250
Pennsylvania Power and Light Company	Docket No. I-830374
UGI - Gas Utility Division	Docket No. R-832331
Duquesne Light Company	Docket No. R-842583
Pennsylvania Power and Light Company	Docket No. R-842651
Pennsylvania Power Company	Docket No. R-842740
Western Pennsylvania Water Company	Docket No. R-850096

Q. WAS THIS TESTIMONY PREPARED UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, it was.

II. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. WHAT GENERAL FINDINGS DO YOU MAKE WITH RESPECT TO THE COMPANY'S COST ALLOCATION AND RATE DESIGN PROPOSALS IN THIS PROCEEDING?

A. I find that both the cost allocations presented by Mr. Sundermeir and the rate design proposals discussed by Mr. Williams fail to properly reflect the importance of energy considerations in the Company's decision to complete the construction of Limerick Unit 1, the primary cause of the requested rate increase in this proceeding. The rationale presented by the Company for its proposed allocation of Limerick Unit 1 costs among customer classes is inconsistent with system planning criteria regarding plant type decisions. The effect of this inconsistency is a distortion of actual cost causation for the Company in the proposed cost allocations, and that distortion, in turn, yields rate designs that greatly mismatch the costs and benefits to be derived from the availability and operation of Limerick Unit 1.

Q. IN PAST CASES THIS COMMISSION HAS DETERMINED THAT COST-OF-SERVICE ANALYSIS IS AN ART, NOT A SCIENCE. DO YOU DISAGREE WITH THIS FINDING?

A. No, I do not. There is always a degree of art in doing a job well. Furthermore, as long as there are areas within cost allocation studies for which no cost causative basis can be identified for distributing cost responsibilities among customer classes, the results of such studies will continue to retain an element of judgment that removes those results from the realm of wholly scientific endeavors. I submit, however, that the real art in the performance of a cost-of-service analysis is found in the analyst's ability to make the study as scientific as possible. Cost-of-service analysts should continually press to narrow the areas in which judgment is necessary. PECO's cost-of-service work in this proceeding, however, clearly has not been approached from that perspective.

Although Limerick 1 represents the largest single addition to rate base ever proposed by the Company, PECO's cost-of-service analysts have apparently made no effort to systematically investigate the reasons for this plant addition. Instead, continued reliance has been placed on rationales which are obviously inconsistent with the Company's own system planning criteria. The same kinds of problems can be found in the Company's distribution system cost analyses.

Rate designs may for many reasons depart from precise adherence to cost-of-service study results, but this fact does not negate the importance of those results as benchmarks against which the Commission may judge the appropriateness of revenue increase distribution and rate design proposals. Rigorous efforts must be undertaken to identify and reflect, to the maximum extent practicable, actual cost causation in cost-of-service study results. Issues that can be decided on the basis of fact must not be left to judgment.

In this case the key cost allocation issue is whether substantial portions of the Company's investment in Limerick Unit 1 were incurred specifically for the purpose of obtaining energy cost savings. If any significant portion of the investment in Limerick 1 is found to be incurred for the purpose of obtaining lower cost energy, then the PECO cost allocation methodology, which suggests that the Company's investment in Limerick 1 was incurred solely for the purpose of meeting peak requirements, must be rejected. I submit that the record in this proceeding supports a determination that much of the investment in Limerick 1 was incurred specifically to attempt to lower the Company's overall production (energy) costs. Thus, it is no longer reasonable or appropriate for the Commission to rely on the results of the Company's Four Summer Peak methodology as a benchmark for judging the merits of alternative revenue increase distributions and rate design proposals. The peak responsibility method of allocating production plant related costs must be replaced by one which provides for a more balanced consideration of both coincident demand and energy factors.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS WITH RESPECT TO THE COMPANY'S COST ALLOCATIONS AND RATE STRUCTURE RECOMMENDATIONS?

A. The major findings and conclusions of this testimony can be summarized as follows:

- In its decisions regarding the types of plant it will build PECO has made explicit trade-offs between the capital costs of new plant alternatives and the anticipated energy costs for operating those plants;
- Portions of plant investment made to obtain lower energy costs are unnecessary for peak reliability considerations, and therefore, are improperly allocated on the basis of peak responsibility methods;
- PECO's Four Summer Peak Method of allocating production plant related costs fails to properly recognize the significant energy component of those costs;

- o The Peak and Average method of production and transmission cost allocation properly recognizes the duality of PECO's capacity expansion decisions which involve decisions regarding both the amount and type of capacity to be added;
- o PECO's cost allocation methods significantly overstate the customer component of distribution system costs;
- o PECO's distribution system cost allocation methods double count the demand-related cost responsibilities of smaller customers;
- o PECO's proposed allocation of Rent from Electric Property is not properly tied to the allocation of cost responsibilities for the portions of electric plant that are rented;
- o PECO's distribution of the revenue increase among customer classes appropriately considers the total revenue requirements of each customer class including fuel costs;
- o When the deficiencies in PECO's cost allocation methods are considered, some modifications to the Company's proposed distribution of the revenue increase are necessary;
- o PECO's proposed residential rate designs do not reasonably distribute cost responsibilities among customers.

Q. WHAT RECOMMENDATIONS DO YOU PRESENT IN THIS TESTIMONY?

A. The major recommendations in this testimony are summarized as follows:

- o PECO's Four Summer Peak Method for allocating production and transmission plant-related costs should be rejected;
- o The results of the Peak and Average cost allocation method should be accepted for use by the Commission as a benchmark for

judging the appropriateness of alternative revenue increase distributions and rate designs.

- The Company should be required to perform a thorough examination of alternative methods for determining customer class responsibilities for distribution system costs for filing with its next base rate case.
- The Company's proposed distribution of the revenue increase among customer classes should be modified in accordance with the results of the Peak and Average allocation of production plant costs presented in this testimony.
- The Company's residential rate designs should be modified to better reflect customers' actual cost responsibilities.
- The initial rate blocks for Rates R and RH should be redesigned in a manner that is more sensitive to the cost burdens placed on customers' essential uses of electricity.

III. COST ALLOCATION ISSUES

Q. HAVE YOU REVIEWED THE COST ALLOCATIONS PRESENTED BY MR. SUNDERMEIR IN PECO EXHIBIT WFS-1?

A. I have.

Q. DO YOU FIND THE RESULTS OF THAT STUDY TO BE REASONABLE AND APPROPRIATE FOR USE IN THIS PROCEEDING?

A. No, I do not.

Q. CAN YOU IDENTIFY SPECIFIC ASPECTS OF THE COMPANY'S PROPOSED COST ALLOCATIONS WITH WHICH YOU FIND SIGNIFICANT PROBLEMS?

A. Yes. In this testimony I identify significant problems in several areas of the Company's cost-of-service analyses. Those areas include:

- The allocation among customer classes of production and transmission plant related costs;
- The identification of customer-related components of distribution system costs;
- The proper development of demand measures for allocating demand-related portions of distribution system costs; and
- The proper allocation from the rental of electric property.

Additionally, it must be recognized that many elements of the Company's costs are allocated on the basis of factors which are directly influenced by the allocations of the production, transmission, and distribution cost allocations discussed above. Thus, we must be mindful of the internal relationships between allocators in assessments of the overall impact of problems identified in the specific areas mentioned above.

Production Plant Cost Allocations

Q. HOW DOES PECO PROPOSE TO ALLOCATE THE PLANT RELATED PORTIONS OF PRODUCTION COSTS AMONG CUSTOMER CLASSES?

A. PECO proposes to allocate those costs on the average of customer class contributions to the Company's four summer month coincident peaks.

Q. WHAT IS THE COMPANY'S STATED RATIONALE FOR THIS APPROACH?

A. According to the cross-examination testimony of Mr. Sundermeir, this method of allocation was chosen to reflect the fact that the Company builds plant to meet peak requirements.

Q. DO YOU AGREE WITH MR. SUNDERMEIR'S RATIONALE FOR USING THE FOUR SUMMER PEAK METHOD OF ALLOCATING PRODUCTION PLANT RELATED COSTS?

A. Only in part. I agree with Mr. Sundermeir that, to a large extent, the amount of capacity which the Company has installed at any point in time is related to its anticipated peak requirements, but the need to satisfy peak demands represents only a partial explanation of costs incurred by PECO for production and transmission facilities. In addition to decisions regarding the amount of plant to be built or maintained on the system, PECO must choose between alternative types of generating facilities. These decisions with respect to the type of plant to be constructed often have a greater influence on the total investment costs incurred by the

Company than decisions regarding the amount of plant to be built. Furthermore, there is a secondary relationship between the type of plant constructed and the amount of capacity required with which we should be aware for cost allocation purposes.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF PLANT "TYPE" DECISIONS FOR THE INCURRENCE OF GENERATING CAPACITY INVESTMENT COSTS BY PECO.

A. The significance of plant type decisions is found in the economic trade-offs made by the Company between capital costs and production costs. These economic trade-offs are addressed directly in the Company's generation capacity planning decisions.

PECO's generation planning must consider both reliability and economics of the capacity that it builds and maintains to serve its customers. PECO's concerns with respect to reliability are primarily a function of the amount of capacity installed and available at any point in time. The Company's decisions with respect to the type(s) of capacity on which it will rely are based on joint consideration of (1) the frequency and duration of system loads and (2) the costs and operating characteristics of alternative generating technologies.

If the Company needs additional capacity primarily to meet loads of relatively short durations (e.g., only on summer peak days), it could build or acquire types of capacity whose costs and operating characteristics are best suited to low capacity factor operations. For such low capacity factor operations, the variable costs of production (i.e., energy costs) are of relatively little importance when compared with the capital costs which must be incurred. Thus, cost minimization criteria tend to encourage the the selection of generating technology alternatives which have low capital costs, even though the variable costs of energy produced by such generators may be relatively high. Typically, low capacity factor generation is provided by combustion turbines or other types of peaking generators.

On the other hand, needs for capacity to satisfy high load factor generation requirements generally call for the selection of technologies whose costs and operating characteristics are best suited to high capacity factor (base load) operation. For these units, which are expected to be utilized intensively over their useful lives, the variable costs of production (i.e., energy costs) are a more substantial concern. The Company's selection from among the available generating technology alternatives must reflect the joint minimization of capital costs and energy costs. Thus, the Company must justify the higher capital costs of base load units by their low production (energy) costs.

There can be no doubt, in light of these considerations, that major portions of the Company's investment in base load generating facilities, such as Limerick Unit 1, have been incurred explicitly to provide lower energy costs. Mr. Sundermeir's testimony, which suggests that the capital costs of such plants were incurred solely to meet peak requirements, thus, fails to accurately portray the cost causative relationships that the Company must necessarily address in its capacity planning process. The production cost allocations presented by Mr. Sundermeir totally ignore the importance of the relationship between capital expenditures for generating plant and the achievement of lower production costs (energy cost savings).

Q. WHAT PORTION OF PECO'S GENERATING UNIT INVESTMENT COSTS CAN BE ATTRIBUTED DIRECTLY TO THE COMPANY'S EFFORTS TO ACHIEVE LOWER PRODUCTION COSTS?

A. The portion of investment that is incurred to gain lower energy costs will vary by plant. For a new base load generator, such as Limerick Unit 1, however, the portion of total investment that is incurred to achieve energy cost savings may exceed 90 percent. For example, Appendix A of the Company's Petition in this case shows a total rate base cost of Limerick Unit 1, including common plant, of $3,710,373,000. This represents a cost of more than $3,500 per kW of installed generating capacity. By comparison, if PECO was only concerned with having sufficient capacity available to meet peak requirements on a few high load days each year, it could have installed an equivalent amount of combustion turbine capacity at a cost of approximately $267 per kW. (OCA Statement 6, page 43) Thus, in building Limerick 1, the Company has incurred more than thirteen times the investment cost necessary to obtain a sufficient amount of capacity to meet coincident peak requirements, and this calculation does not address the retirement of existing generating units. We must, therefore, conclude that for each kW of Limerick capacity, at least $3,233 (i.e., more than 92 percent) were incurred to obtain lower production costs.

Q. WHAT IS THE SECONDARY RELATIONSHIP BETWEEN THE "TYPE" DECISIONS AND THE AMOUNT OF CAPACITY WHICH MUST BE INSTALLED TO WHICH YOU EARLIER REFERRED?

A. The economics of base load generation tend to be dependent on the construction of very large scale units. This is particularly true for nuclear plants. On the other hand, combustion turbine capacity can be added economically in smaller, more dispersed units. Since an unexpected outage of a single large (1,000+ MW) nuclear generator can have a greater impact on system reliability than numerous outages of smaller combustion turbine units, there tends to be a reliability penalty associated with the dependence on large base load nuclear plants. As a result, a greater total amount of capacity may be required to maintain a given level of system reliability if large nuclear generating units are utilized. The amount of capacity required by the Company is, therefore, also determined, at least in part, by decisions regarding the types of generators employed, i.e., the capacity mix. I submit that where it can be shown that added generating capacity reserve requirements can be attributed directly to the addition of large base load generating units to the system, the capacity costs associated with such incremental reserve requirements should be allocated wholly on an energy basis.

Q. WHO SHOULD BEAR THE ADDED CAPACITY COSTS INCURRED TO AS A RESULT OF CAPACITY "TYPE" DECISIONS?

A. Customers should bear responsibility for those costs in proportion to the benefits they derive from those investments. The primary benefits from the incurrence of higher capital costs are lower production (energy) costs, and those benefits are experienced by customers on an equal cents per kWh basis. Thus, it is both reasonable and appropriate to distribute responsibility for capacity "type" related investment decisions in proportion to each customer's, or each class's energy use.

Q. HOW DO YOU PROPOSE TO ALLOCATE PRODUCTION PLANT RELATED COSTS AMONG CUSTOMER CLASSES?

A. I propose the use of the Peak and Average Demand Methodology for allocation production of plant related costs in this proceeding. I believe that this method of cost allocation reasonably reflects the duality of the Company's generating capacity planning decisions. The Peak portion of the Peak and Average Method recognizes the amount of capacity required, while the Average portion of the Peak and Average Method gives weight to the Company's decisions regarding the type(s) of capacity required. Neither an all-energy (average demand) allocation nor an all-demand (coincident peak) allocation of the Company's production plant related costs is acceptable because neither, by itself, captures both essential elements of the capacity planning process. I also note that the significance of the portions of the Company's recent investments in generating plant that are clearly in excess of those required simply to meet peak requirements suggests that reasonable weightings of capacity type and capacity amount considerations should probably yield a result that is weighted more toward an all-energy result than toward a strictly demand oriented allocation.

I find the use of non-coincident demand measures, either by themselves or as part of a Standard Average and Excess Demand allocation, to be wholly inappropriate for production cost allocation for this utility. Coincident peak demands and average demand (energy) measures can be tied directly to the Company's capacity planning decision criteria, but there is no evidence that class non-coincident demand measures play any significant role in the capacity planning process.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF YOUR PROPOSED PEAK AND AVERAGE ALLOCATION FACTORS.

A. The development of the Peak and Average allocation factors that I have used is straightforward and easily understood. It is in essence a weighting of the Company's A1 and C1 allocators. The A1 allocator which represents the class contributions to the Company's average of four summer month coincident peaks constitutes the Peak portion of the Peak and Average allocation factor. The Average portion of the Peak and Average method is reflected in the use of the Company's C1 allocator. The C1 allocator measures the fraction of annual energy requirements that is attributable to each customer class, and by definition the C1 value for each class must equal the class' proportionate contribution to system average demands.

The weighting of these to elements is based on the system annual load factor. The Average portion of the allocator is weighted by the system load factor (LF), and the Peak portion is weighted by a value equal to one minus the system load factor (1-LF). This weighting method can also be tied to the Company's capacity planning considerations since, for any given amount of capacity, the average capacity factor for the system will increase with the system load factor. Thus, the weight attributed to capacity <u>type</u> decisions (i.e., decisions to incur additional capital costs for the purpose of lowering energy costs) is increased with increases in the system load factor, and decreased with lower system load factors. Correspondingly, the weight attributed to decisions regarding the <u>amount</u> of capacity required declines as system load factor increases and rises with a decrease in system load factor.

The development of Peak and Average allocation factors for PECO is shown in Schedule BRO-1.

Q. WHAT EFFECT DOES YOUR PROPOSED CHANGE IN THE ALLOCATION OF PRODUCTION PLANT COSTS HAVE ON CUSTOMER CLASS RATES OF RETURN?

A. The results of a reallocation of PECO costs using the Peak and Average allocation factors in place of the Company's A1 allocator are summarized in Schedule BRO-2. These results yield some significant changes in customer class relative rates of return. Most significantly the rate of return for the HT class falls further below the system average while the rates of return for all other major classes are above the system average. Also within the residential class there is a sharp reversal of positions, with the rates of return for RH and OP falling well below the system average while the rates of return for Rate R and for the total residential class move slightly above the system average level.

Distribution System Cost Allocations

Q. HOW DOES PECO PROPOSE TO ALLOCATE DISTRIBUTION SYSTEM COSTS AMONG CUSTOMER CLASSES?

A. PECO determines class responsibilities for distribution system costs in two steps. First, the Company uses a "predominant" minimum system approach to classify costs between customer and demand components. Then the classified costs are allocated among customer classes using a variety of customer and demand allocators.

Q. WHAT PROBLEMS DO YOU FIND IN THESE METHODS?

A. The rationale applied by the Company in these allocations are inconsistent and result in a double counting of demand responsibilities for smaller customers. In addition, the Company's predominant minimum system approach is inconsistent with the identification of facilities necessary to serve "nominal" load requirements which the NARUC Cost Allocation Manual specifies as the basis for determining the customer component of distribution system costs.

In general, PECO's approach to distribution system cost allocation has not advanced with the state-of-the-art. It has continued to rely on older and less preferred methods, which judgmentally place greater cost burdens on smaller customers, and it has presented no evidence of even considering alternative approaches.

Q. WHAT IS THE SIGNIFICANCE OF PECO'S RELIANCE ON OLDER AND LESS PREFERRED METHODS OF COST ALLOCATION?

A. The NARUC Manual on which the Company relies for support for its minimum system approach for classifying distribution plant costs was published in 1973. At that time nearly thirteen years ago, NARUC recognized only two approaches for identifying the customer component of distribution system costs, the minimum-intercept method and the minimum size method. The NARUC Manual, which generally is not a prescriptive document, however, stated a clear preference for the use of the Minimum-Intercept Method. Thus, even in 1973 the minimum size method used by the Company was the less preferred approach, at least in part, because of the greater amount of judgment it requires. Essentially the minimum system method was viewed as a fall back position when sufficient data were not available to perform a minimum-intercept analysis.

Since the publication of the NARUC Manual, at least two other approaches to distribution cost classification have gained some acceptability. Like the preferred Minimum Intercept Method, both of these newer alternatives tend to produce lower measures of customer-related costs than the Company's method. One is the Modified Zero Intercept Method, which has been used in various forms in recent filings by at least three other electric utilities in Pennsylvania, including Duquesne Light Company, Pennsylvania Power Company, and Pennsylvania Power and Light Company. The other method is one which has recently gained acceptance with the New Jersey Board of Public Utilities. That method is based on a determination that only meters and services have customer related components and all other elements of distribution costs are most appropriately allocated on the basis of demand measures.

Q. HAS PECO PERFORMED ANY ANALYSIS OF THESE ALTERNATIVES OR ATTEMPTED TO APPLY THEM TO DATA FOR ITS SYSTEM?

A. No. There is no evidence that PECO has made any attempt to investigate any of these alternatives.

Q. WOULD A THOROUGH EXAMINATION OF THESE ALTERNATIVE METHODS BE BURDENSOME FOR THE COMPANY?

A. No, I do not believe it would be. In fact, this Commission has required similar efforts of other utilities in the state in recent years. For example, in its Opinion and Order in Docket No. R-822169, the Commission asked the Pennsylvania Power and Light Company (PP&L) to reexamine its methods for determining customer class responsibilities for distribution system costs. PP&L's subsequent filing in Docket No. R-842651 reflected the Company's response to that request. In place of its former minimum system method for determining the customer component of distribution system costs PP&L presented a Modified Zero Intercept Method. The difference in results for residential customers was significant. The total customer-related dollars of distribution costs was nearly 20 percent lower under the Company's modified zero intercept method in Docket No. R-842651 than it was roughly two years earlier under the minimum system approach.

For these reasons I recommend that the Commission order PECO to examine alternatives to its present methods for determining class responsibilities for distribution system costs. Furthermore, in light of this recommendation, I will limit my discussion of PECO's distribution cost allocation proposals in this proceeding to documentation of major problems and steps that can be taken within the context of the Company's present methods to yield more reasonable results for use in this case.

Q. DOES PECO'S PREDOMINANT MINIMUM SYSTEM APPROACH ACTUALLY IDENTIFY JUST THE CUSTOMER-RELATED PORTIONS OF DISTRIBUTION SYSTEM COSTS?

A. No, it does not. As Mr. Sundermeir stated under cross-examination, certain portions of the Company's predominant minimum system specification, such as customer service drops, actually contain sufficient load carrying capabilities to meet the maximum demands of most residential customers. (Tr. 1813) Furthermore, Mr. Sundermeir also stated that the "predominant" minimum size equipment for the PECO system may change over time as the demands on the system increase. (Tr. 1826-27) Thus, increases in customer demands can result in an increase in the portion of distribution costs that PECO classifies as customer-related costs.

For example, Mr. Sundermeir stated under cross-examination that in some prior time period the "predominant minimum size" transformer for PECO may have been 10 kVa. (Tr. 1826-27) Today PECO's "predominant minimum size" transformer is considered to be 25 kVa. In the future, according to Mr. Sundermeir, the Company's "predominant minimum size" transformer may be even larger if increasing demands on the system caused the Company to install proportionately more transformers over 25 kVa in size. (Tr. 1827)

The costs of a 15 kVa transformer installed when the predominant minimum size transformer was 10 kVa would have been classified as partly customer-related and partly demand-related. If that same 15 kVa transformer was still in service when the Company increased the predominant minimum size of equipment it was installing to 25 kVa, the portion of the costs of that 15 kVa transformer that previously was classified as demand-related would, under the Company's methods, be reclassified as customer costs. This is totally contrary to any rational concept of customer-related cost responsibilities.

Q. SHOULD THE DETERMINATION OF THE CUSTOMER COMPONENT OF DISTRIBUTION SYSTEM COSTS BE REFLECTIVE OF "REAL WORLD" CONDITIONS RATHER THAN THEORETICAL CONSTRUCTS?

A. No. The customer component of distribution plant is necessarily a theoretical construct. If a customer had no current or anticipated demand for electricity, then it is unlikely that the customer would ever request service from the Company, or that facilities would be installed to connect the customer to the Company's system. Customers' demands and service requirements are inextricably tied. It is for this reason, that the NARUC

Manual, at page 56, defines the customer component of distribution facilities as the "theoretical minimum distribution system required to serve customers at nominal load conditions." (Emphasis added.) Mr. Sundermeir, however, apparently does not support the NARUC Manual's definition of the customer component of distribution facilities costs.

During cross-examination on his direct testimony in this case, Mr. Sundermeir asserted that the customer component should represent a "practical minimum," not a "theoretical minimum." (Tr. 1828) My problem with Mr. Sundermeir's concept of a "practical minimum" system lies in the determination of what is practical. I suspect that what is considered practical by current distribution system planners in the context of presently anticipated customer load requirements is quite different from what the same planners would design if confronted with expectations of substantially lower customer demands. Thus, we can begin to appreciate the cautions of the NARUC manual with respect to the more judgmental character of the minimum system method.

Similarly, Mr. Sundermeir's rebuttal testimony in Docket No. R-842590, touted the fact that "the Company's predominant minimum size method reflects conditions as they actually exist on PECO's distribution system" (PECO Statement 11A, page 17) as if it were a strength of that approach. The portrayal of actual conditions, however, is a severe drawback in this type of analysis, not a strength. By consciously including demand-related expenditures in the customer component of costs, the Company's methods distort the very purpose of the analysis, that is, to separate jointly incurred expenditures into demand-related and customer-related components. A simple depiction of "real world" conditions is, thus, an inappropriate and unacceptable answer to distribution system cost classification issues.

Q. IN WHAT MANNER DO PECO'S DISTRIBUTION SYSTEM COST ALLOCATIONS DOUBLE COUNT THE DEMAND RESPONSIBILITIES OF SMALLER CUSTOMERS?

A. While it is apparent that the Company's predominant minimum size facilities include substantial ability to serve customers' loads, the Company's allocators for the demand-related portions of distribution system costs make no allowance for customers demands that are fully satisfied by minimum size facilities. As a result, customers who make no contribution to the need for facilities in excess of minimum system specifications are allocated a portion of the cost responsibility for those excess facilities. This is clearly inequitable.

Q. DO YOU HAVE ANY OTHER COMMENTS WITH RESPECT TO THE COMPANY'S DETERMINATIONS WITH RESPECT TO THE CUSTOMER COMPONENT OF DISTRIBUTION SYSTEM COSTS?

A. Yes. The problems with respect to the double counting of demand responsibilities for smaller customers is further exacerbated at the primary distribution level under the Company's predominant minimum system methods. Since the predominant minimum sizes of equipment at the primary level specified by the Company frequently have even greater load carrying capabilities than the predominant minimum size secondary system facilities, the amount of double counting included in PECO's minimum size primary system facilities must necessarily be greater. Only through the imputation of further demand-related considerations can a requirement to increase the sizing of primary facilities be justified. Absent demand-related considerations, there can be no basis for distinguishing between primary and secondary system requirements.

Q. HOW WOULD YOU PROPOSE TO CORRECT FOR THESE PROBLEMS IN PECO'S DISTRIBUTION SYSTEM COST ALLOCATIONS?

A. In the context of the Company's proposed methods in this proceeding, I recommend that two adjustments be made. First, the secondary distribution system demand allocators should be modified to eliminate the portions of customers' demand requirements that are fully satisfied by PECO's predominant minimum system facilities. Second, the customer components of primary distribution lines costs should be reduced to to be consistent with those for secondary lines since only demand-related factors would yield higher costs at the primary level. Once again, I note that these recommendations for modifications to the Company's distribution system cost allocations in no way represent an endorsement of those methods or an acceptance of their appropriateness. As I earlier testified, the Company should be required to thoroughly re-examine its approach to these allocations.

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS TO THE COMPANY'S DEMAND ALLOCATORS.

A. To reduce the double counting of customer demands that occurs under the Company's cost allocation methods, I have eliminated from the Company's demand allocators for secondary lines, transformers, and services amounts of demand equal to the maximum requirements of the smallest size residential customers for whom load research results were available. This was accomplished by subtracting 3.453 kW per customer from the secondary lines and services demands for each class and 1.440 kW per customer from each classes demands at the secondary transformers. The kW per customer measures used to make these adjustments in the Company's demand allocators are based on the annual per customer diversified maximum demands and noncoincidental maximum demands reported for residential customers in the 0-300 kWh usage stratum in the Company's 1980 Residential Electric Service Load Study. I believe these adjustments are conservative in light of Mr. Sundermeir's testimony regarding the load carrying capabilities of the facilities included in PECO's minimum system.

Q. HOW DID YOU CALCULATE THE CUSTOMER COMPONENT OF PRIMARY DISTRIBUTION LINES COSTS FOR PECO?

A. The Company's workpapers for its minimum system costs are provided in the attachment to its response to interrogatory IR-OCA-7-8. Reflected in those workpapers is a 1982 analysis of equipment installed as of December 31, 1981 which shows higher costs per conductor foot for PECO's predominant minimum size facilities at the primary level than at the secondary level for both aerial and underground lines. Recognizing that, absent increased demands, there would be no need to increase the sizing of primary system lines, I recomputed the customer components of primary lines, aerial and underground, by multiplying the costs of the predominant minimum size secondary lines times the total of feet of primary conductor installed as of December 31, 1981. The resulting dollar figures were then divided by the total costs of primary lines installed as of the same date, and the resulting decimal fractions, for aerial and underground, were used to identify the customer components of test year costs for primary lines.

Although these revised customer component calculations represent less than a fully satisfactory removal of demand-related costs from the customer components of primary lines costs, I believe they constitute a conservative, yet important, step in the direction of more accurate depiction of customer-related cost responsibilities. These revisions result in a reduction of the customer component of primary aerial lines from 81.2 percent to 63.0 percent. For underground primary lines the customer component is lowered from 87.4 percent to 49.1 percent.

Q. WHAT ARE THE RESULTS OF YOUR CHANGES IN THE COMPANY'S DISTRIBUTION SYSTEM COST ALLOCATIONS?

A. The results of these changes in the Company's distribution system cost allocations are presented in Schedule BRO-3. Not unexpectedly, the effects of these changes are greatest for classes of customers that take service at the secondary distribution level. Within the general category of secondary service customers, however, the most notable result is the improvement in the rate of return for Rate R customers.

Other Cost Allocation Issues

Q. DO YOU HAVE COMMENTS ON OTHER ASPECTS OF PECO'S COST ALLOCATIONS?

A. Yes, there is also a problem with the proposed allocation of Rents from Electric Property.

Q. HOW HAS PECO ALLOCATED REVENUE FROM THE RENTAL OF ELECTRIC PROPERTY?

A. PECO has proposed to allocate all of this revenue on the basis of its average of four summer month coincident peaks.

Q. DO YOU FIND THE COMPANY'S METHOD OF ALLOCATING THESE COSTS TO BE REASONABLE AND APPROPRIATE?

A. No, I do not. Accepting arguendo the appropriateness of PECO's four summer peak allocator, its use in this application would only be appropriate if the vast majority of such revenues were derived from the rental of production or transmission property. Mr. Sundermeir's recollections, however, were that the primary source of these revenues is rents for "pole attachments by Bell Telephone." (Tr. 1754) The Company's bases for allocating cost responsibilities for distribution poles are quite different from that used for production and transmission plant. Thus, the Company's allocation of these rental revenues is not consistent with distribution of cost responsibilities for the property that is rented.

Q. HOW SHOULD RENTS FROM ELECTRIC PROPERTY BE CREDITED TO CUSTOMER CLASSES?

A. Rents from electric property should be credited to customer classes in a manner consistent with the allocation of cost responsibilities for property rented. In the absence of any information contradicting Mr. Sundermeir's recollections with respect to the primary source of these rents, I believe that the the most appropriate basis for allocating these revenues is to spread those revenues among classes in proportion to their responsibilities for costs in Account 364.

Q. WHAT INFLUENCE DOES YOUR CHANGE IN THE TREATMENT OF RENTS FROM ELECTRIC PROPERTY HAVE ON THE DISTRIBUTION OF COST RESPONSIBILITIES AMONG CUSTOMER CLASSES?

A. This change does not have a large impact on rates of return by class, but it does redistribute more than 4.2 million dollars of revenues from the HT and PD classes to other customer classes.

Q. HAVE YOU PREPARED A SUMMARY OF THE CUMULATIVE EFFECTS OF ALL OF THE COST ALLOCATION CHANGES THAT YOU HAVE DISCUSSED?

A. Yes, that summary is provided as Schedule BRO-4.

Q. HOW DO THE CUMULATIVE EFFECTS OF YOUR PROPOSED CHANGES IN COST ALLOCATION METHODS COMPARE WITH THE RESULTS OF THE COMPANY PROPOSED COST ALLOCATIONS?

A. A comparison of class rates of return at present rates under the Company's cost allocation methods (PECO Study) and under the composite of the cost allocation revisions that I have recommended (OCA Study) is presented below:

	Percent of System Average Rate of Return	
Rate	PECO Study	OCA Study
Residential	100	106
Rate R	96	114
Rate RH	116	80
Rate OP	343	31
General Service	96	94
Rate GS	126	135
Rate PD	97	108
Rate HT	84	77
Street Lighting	197	163
Septa & Amtrak	135	104

IV. DISTRIBUTION OF THE REVENUE INCREASE

Q. HOW DOES PECO PROPOSE TO DISTRIBUTE ITS PROPOSED REVENUE INCREASE AMONG CUSTOMER CLASSES?

A. The Company's basic proposal is to spread the revenue increase in a manner that produces roughly equal net percentage increases for each class. The Company accomplishes that distribution by applying an across-the-board increase to present revenues of each class, including fuel costs. Three exceptions are made, however.

First, those classes whose indexed (relative) rates of return at present rate levels, under PECO's proposed cost allocations, are greater than 140 percent receive zero net increases (i.e., their increases were set to exactly offset their allocated fuel cost savings).

Second, the increase to Rate RH customers is held below the system average increase percentage to prevent the relative rate of return for that class from moving further from the system average. Under the Company's cost allocations, the relative rate of return for Rate RH is 16 percent above the system average at present rate levels. The application of the full across-the-board increase to Rate RH would have raised the Company's calculation of that class' relative rate of return further above the system average.

Third, rate increases for SEPTA and AMTRAK are set in a manner that causes the rate of return for each of those customers to exactly equal the system average. The Company's position is that this measure appropriately establishes the initial rates for those customers at levels that reflect their individual cost responsibilities. Thus, the proposed net percentage increases for those customers are only about half the magnitude of the across-the-board increase percentage.

Q. DO YOU FIND THE COMPANY'S ALLOCATION OF THE PROPOSED REVENUE INCREASE TO BE REASONABLE AND EQUITABLE?

A. I generally agree with the rationale which the Company uses to distribute the increase among customer classes, but I find that the application of its rationale is distorted by the previously discussed shortcomings in the Company's cost-of-service study results. This is particularly true with respect to PECO's apportionment of cost responsibilities for Limerick Unit 1. Once again, the fact that PECO's investment in Limerick 1 that was incurred primarily in an attempt to obtain lower energy costs cannot be ignored. Those customers who receive the benefits of that investment should bear proportionate responsibility for its costs. For this reason, the combination of PECO's rationale for distributing the rate increase and its cost-of-service study results does not produce an equitable matching of costs and benefits.

Q. INCLUDED IN THE COMPANY'S RATIONALE FOR ALLOCATION OF THE PROPOSED RATE INCREASE IS CONSIDERATION OF FUEL COSTS. DO YOU FIND THAT ASPECT OF THE COMPANY'S METHODOLOGY TO BE REASONABLE?

A. Yes, I do. The consideration of fuel costs in the distribution of the proposed rate increase in this proceeding is both reasonable and appropriate in light of the primary cause of this increase.

Q. WHAT CHANGES DO YOU RECOMMEND IN THE DISTRIBUTION OF THE PROPOSED REVENUE INCREASE AMONG CUSTOMER CLASSES?

A. I recommend that the Company's basic rationale be adopted, but applied in the context of the revised cost allocation results that I have presented in Schedule BRO-4. That combination suggests that certain modifications to the Company's proposed revenue increase distribution are necessary. In essence, those classes whose actual responsibilities for Limerick 1 costs exceed those which they are allocated under the Company's cost allocation methods are called upon to bear a greater share of the burden of this increase.

Schedule BRO-5 shows the customer class rates of return that result when the Company's proposal for distributing the rate increase is viewed in the context of the OCA recommended cost-of-service study results. In light of the customer class rates of return found in that schedule, I find that the following modifications to the Company's allocation of the revenue increase are warranted:

- Greater increases should be applied to SEPTA, AMTRAK, and the Street Lighting classes to raise their respective rates of return to the system average level. It should be noted that each of these classes still receives a less than system average net percentage increase;
- The net percentage increase to Rate OP customers should be raised to equal the system average increase as partial compensation for that class' very low relative rate of return under the OCA cost allocation results;
- The additional revenues derived from SEPTA, AMTRAK, and the Street Lighting classes should be used to reduce the revenue increase for Rate GS customers;

- o The additional revenues from Rate OP customers should be kept within the residential class and used to reduce the revenue increase for Rate R customers;
- o The remaining discrepancy between the rates of return for Rate R and Rate RH should be addressed within the framework of residential rate design considerations since the charges applied for those two classes have been closely linked in recent years.

The resulting dollar adjustments to the Company's proposed rate increases by class are shown in Schedule BRO-6. The class relative rates of return that result from the combination of the OCA cost allocation and revenue increase distribution recommendations are listed below:

Rate Class	Percent of System Average Rate of Return
Rate R	108
Rate RH	85
Rate OP	67
Residential	103
Rate GS	119
Rate PD	106
Rate HT	90
General Service	99
Street Lighting	100
Septa & Amtrak	100

Q. IF THE OVERALL REVENUE INCREASE GRANTED BY THE COMMISSION IS LESS THAN THAT REQUESTED BY PECO, HOW SHOULD THE DISTRIBUTION OF THE REVENUE INCREASE BE ADJUSTED?

A. My recommendations for distributing the revenue among classes to recover the fully requested increase are sensitive to the magnitude of the overall revenue increase. Considering the size of PECO's overall request, I feel compelled to avoid any adjustments to the Company's allocation of the revenue increase that would cause a class of customers to bear an increase that is substantially greater than system average. This means that classes, such as Rate OP, Rate RH, and Rate HT, which are shown to have rates of return well below system average at proposed rate levels, receive less of an upward adjustment than they would have if the overall rate increase were less.

If the Company should be granted less than its full increase request, however, opportunities are then provided to introduce greater differences in the revenue increase percentages borne by the various classes without placing an excessive burden on those classes that receive higher than average increases. Any adjustment to the distribution of the revenue increase under those circumstances should, thus, be structured to provide greater rate relief to those classes of service whose rates of return are above the system average. In other words, the percentage reductions in revenue requirements for Rates GS, R, and PD should be greater than those for Rates HT, RH, and OP. I recommend, however, that all classes, regardless of their calculated rates of return, share substantially in the benefits of a reduction in the Company's requested rate increase. This could be accomplished by spreading 80 percent of any rate reduction in proportion to the dollar increases applied to each class and using the remaining 20 percent to achieve further balancing of class rates of return.

V. RESIDENTIAL RATE DESIGN

Q. HAVE YOU REVIEWED THE CHANGES IN RESIDENTIAL RATES PROPOSED BY THE COMPANY IN THIS PROCEEDING?

A. Yes, I have.

Q. WHAT CHANGES IN THE RESIDENTIAL RATE DESIGNS ARE PROPOSED BY PECO?

A. The changes proposed by PECO for the charges in Rates R and RH are summarized below:

Charge	Present Rates	Proposed Rates	Percent Increase
Customer	$ 4.50	$ 4.75	5.5
Up to 500 kWh	0.1035	0.1362	31.6
kWh Over 500 Winter			
Rate R - Winter	0.1035	0.1362	31.6
Rate R - Summer	0.1180	0.1566	32.7
Rate RH - Winter	0.0593	0.0705	18.9
Rate RH - Summer	0.1180	0.1566	32.7

Q. WHAT GENERAL CONCERNS DO YOU HAVE WITH RESPECT TO PECO'S RESIDENTIAL RATE DESIGN PROPOSALS IN THIS CASE?

A. I have two major areas of concern with respect to those proposals. First, I find considerable reason to question whether the proposed residential rate designs provide a proper reflection of the reasons for the substantial increase requested by the Company in this case. Second, I question whether the Company has adequately considered the impacts of the proposed rate increase on the costs of energy to meet customers' essential needs for electricity.

Q. HOW DOES THE CAUSE OF THE RATE INCREASE IN THIS CASE RELATE TO RESIDENTIAL RATE DESIGN CONSIDERATIONS?

A. As I have previously demonstrated, the vast majority of the costs of adding Limerick 1 were incurred, not to meet peak capacity requirements, but in an attempt to provide lower energy costs. The Company's rates to residential customers should, therefore, reflect to customers the fact that the energy savings that they experience from the operation of Limerick 1 have only been obtained as the result of the incurrence of substantial capital costs. With recognition of the costs of Limerick 1, the difference in cost to the Company between meeting an additional kW of demand at the time of its annual system peak and an additional kW of demand throughout most of the hours of the year, except those on summer peak days, is greatly diminished. If we fail to properly reflect these cost relationships to customers, we will encourage a greatly distorted perception of the costs to the Company of providing service.

Q. WHY DO YOU QUESTION WHETHER THE COMPANY HAS ADEQUATELY CONSIDERED THE EFFECTS OF ITS PROPOSED RATE INCREASE ON THE COSTS OF MEETING RESIDENTIAL CUSTOMERS' ESSENTIAL REQUIREMENTS FOR ELECTRIC ENERGY?

A. Under the phase-in proposal set forth by the Company the average customer will experience rate increases of approximately 9 to 10 percent per year for each of the next four years. If PECO finds the need to request another rate increase within that time frame, the annual increases that customers experience may be even greater. Recent increases in the general cost of living have only been in the range of 3 to 5 percent on annual basis, and it appears that inflation rates are generally expected to rise only slightly over the next few years. Since there tends to be a fairly high correlation between increases in the general cost of living and increase in average incomes, it is likely that PECO's electric rates for residential customers will consistently outpace the rate of growth in the average customers' income in each of the next four years and maybe longer. This will require that customers steadily increase the portions of their incomes that are dedicated to paying their electric bills.

Where customers can reduce nonessential uses of electricity, the effects of these increase can be moderated. Customers cannot, however, be expected to reduce essential uses of electricity. Thus, customers with some nonessential electrical uses may be able to avoid some of the impact of the proposed rate increase by once again trimming those requirements, but the full impact of this rate increase will be unavoidable for customers' essential uses.

Q. APART FROM CONCERNS WITH RESPECT TO CUSTOMERS' ESSENTIAL ENERGY NEEDS, ARE PECO'S PROPOSED RESIDENTIAL ENERGY CHARGES REASONABLE?

A. No, I find that some adjustments to those rate design proposals are necessary whether or not measures are taken to address the impact of the proposed rate increase on customers' essential uses of electricity. PECO's proposed increase for the winter tail block for residential space heating customers is considerably below the average increase for the residential class. This fails to properly reflect the cost responsibilities of customers served in that block. The usage served under this tail block will receive substantially the same level of benefit per kWh from the addition of Limerick 1 as other residential usage, but the proposed increase for this block is equal to only about 60 percent of the increases proposed for other residential energy block charges.

The Company's response to Interrogatory IR-OCA-7-4 indicates that the charge for the Rate RH winter tail block (i.e., use in excess of 500 kWh) was set simply to recover the balance of the revenue requirement after all other charges for Rates R and RH were determined. Thus, there is no direct tie between the level of the Rate RH winter tail block charge and the costs to the Company of providing service to those customers.

The present Rate RH winter tail block charge is approximately 4.4 cents per kWh less than the comparable Rate R charge for the same service. That existing differential is based on PECO's argument that Rate RH tail block use during winter months is of a "seasonally off-peak nature". When more than 92 percent of the costs of new generating plant are incurred in an attempt to provide energy cost savings on a year-round basis, the significance of such seasonal off-peak cost differentials should be diminished. The Company's proposed residential rate designs, however, substantially and unjustifiably increases that differential to approximately 6.6 cents per kWh.

From the residential bill comparisons provided by the Company in the attachment to IV-D-1, it can be determined that the average Rate RH customer is expected by the Company to experience about $15.63 per winter month in fuel cost savings as a result of the addition of Limerick. By comparison the average Rate R customer will receive less than $3.00 per month in fuel cost savings from Limerick. Clearly, a matching of the costs and benefits of the addition of Limerick 1 suggests that Rate RH winter use should bear a more proportionate share of the residential revenue increase in this case. Adoption of the Company's proposed residential rate design would mark a return to the types of unjustified, promotional ratemaking for residential electric heating that were experienced in the late 1960's and early 1970's.

Q. IS PECO'S PROPOSED RESIDENTIAL CUSTOMER CHARGE REASONABLE?

A. This Commission in several recent cases has determined that the residential customer charge should be limited to recovery of customer-related costs associated with metering and billing. Although I differ with some of the specific cost elements included in the analysis used by the Company to support that charge, I find that the level of the Company's proposed residential customer charge in this case appears within the limits of acceptability.

Q. WHAT CHANGES IN RESIDENTIAL RATE DESIGN DO YOU PROPOSE?

A. My recommendations for PECO's residential rate designs are twofold. First, I propose an increase in the winter tail block for Rate RH customers coupled with a slight decrease in the initial block for both Rate R and Rate RH. Second, I propose that the Company residential rate blocks be modified to reduce the impacts of PECO's proposed rate increase on customers' essential uses of electricity.

Q. PLEASE EXPLAIN YOUR PROPOSAL FOR INCREASING THE WINTER TAIL BLOCK FOR RATE RH CUSTOMERS?

A. I recommend that the increase for the winter tail block (i.e., the charge for use in excess of 500 kWh per month) of Rate RH be set equal to 92 percent of the average percentage increase for the residential class. Setting the increase for the Rate RH winter tail block in this manner appropriately reflects to those customers the costs of of Limerick 1 that have been incurred to generate the energy cost savings that they should experience. I recommend further that the additional revenues generated by increasing the Rate RH winter tail block charge be used to lower the level of the charge for use in the first 500 kWh block of both Rates R and RH. The specific charges that would be required to implement this change are presented in Schedule BRO-7.

Q. PLEASE EXPLAIN YOUR PROPOSAL FOR ESSENTIAL USE BASED RATE BLOCKS.

A. My recommendation for the establishment of rate blocks based on customers' essential uses is designed to help maintain the affordability of electricity for basic human needs during a period when the costs of electricty are rising faster than customers' incomes. Essential uses would be divided into three categories:

- o Basic use requirements (including electricity for basic lighting, refrigeration, cooking, clothes washing, and communications needs);
- o Electric water heating requirements; and
- o Electric space heating requirements during winter months.

For each of these essential use categories, monthly use allowances are established. The basic use allowance plus the allowances for major electrical appliances (i.e., electric water heaters and electric space heating equipment), if applicable, provide the basis for determining customers essential requirements. Based on my review of appliance usage information in the Company's 1984-1994 Electric Forecast, as well as appliance usage data from the Edison Electric Institute (EEI) and other utilities, I have developed the following monthly kWh use allowances for the three categories of essential uses identified above:

Basic Uses	350 kWh per month
Water Heating	350 kWh per month
Space Heating	700 kWh per winter month

Under my proposal for rate blockings based on customers' essential requirements for electricity, these kWh allowances form the basis for establishing the length of the initial use block for each customer. Thus, instead of providing an initial block of 500 kWh per month for all customers, the amount of usage in each customer's initial, or essential use, block is tied to the customer's essential needs for electricity.

Customers who do not use electricity for either space heating or water heating will find their initial rate block shortened to 350 kWh per month (i.e., the basic use allowance). Customers with electric water heating will receive an additional 350 kWh per month allowance, thus expanding their initial block to a total of 700 kWh per month. Likewise, electric space heating customers will be allowed an initial rate block of 1,050 kWh per month during winter billing months if they do not also have electric water heating, or 1,400 kWh per month if they use electricity for both space heating and water heating.

Using these initial rate block definitions, the increases in rates for essential uses of electricity are established at levels which are more comparable to increases in the overall cost of living. Since greater increases will almost necessariy be applied to all other residential electric use, the net result is a more refined application of the inverted rate concept which is already incorporated in PECO's residential rate designs.

Q. HOW DO YOU PROPOSE TO IMPLEMENT THIS PROPOSAL WITHOUT GREATLY EXACERBATING THE RATE INCREASES FOR CUSTOMERS WHOSE USAGE EXCEEDS YOUR ESSENTIAL USE LEVELS?

A. My proposal is that the implementation of this essential use concept be accomplished primarily through the reductions in the Company's requested rate increase. As the amount of increase to the residential class is lowered those revenue reductions would be applied first to reduce the charges for essential use. Adjustments made in this manner ensure that no customer will receive a greater increase than that proposed by the Company in this case while providing necessary rate relief to those uses of electricity which are most inelastic and, therefore, least amenable to conservation in the face of large rate increase. This approach also ensures that all customers will receive some benefit from any rate reduction since <u>all</u> customers are provided a basic use allowance and, thus, necessarily consume energy in the initial essential use blocks.

Q. HOW WOULD YOUR ESSENTIAL USE BASED RATE DESIGN PROPOSALS BE IMPLEMENTED IF THE COMMISSION GRANTS THE COMPANY'S FULL REVENUE INCREASE REQUEST?

A. Should the Commission grant the entirety of the Company's requested increase, I expect that it will find itself in a most untenable position.

Due to the magnitude of that increase, there will be no way for the Commission to ensure the affordability of essential uses of electricity without placing even higher increase on other customers, either by further increasing the charges for the existing excess use (tail) blocks in rates R and RH or by shifting revenue requirements to other classes. If no action is taken to moderate the rate increases for essential electricity requirements of PECO of customers, then many customers on low or fixed incomes may be unable to continue their electrical use and meet their other basic subsistence needs (e.g., food, clothing, and shelter).

Q. WHY CAN'T CUSTOMERS ESSENTIAL NEEDS BE ADDRESSED WITHIN THE COMPANY'S EXISTING RESIDENTIAL RATE BLOCK STRUCTURE?

A. The existing rate blocks provide only an imprecise method of identifying customers' essential electric requirements. For many customers the initial 500 kWh block provides for more use than is necessary to meet their essential needs. For others, particularly, water heating and space heating customers, the initial 500 kWh block falls considerably short of their essential needs. Furthermore, the proportion of total residential use that falls within the initial 500 kWh block represents nearly 70 percent of all residential sales. Thus, any substantial decrease in the proposed charges for the initial 500 kWh block could result in severe exacerbation of the already large increases proposed for the above 500 kWh blocks.

Q. ARE THE COMPANY'S EXISTING NON-RATE PROGRAMS FOR ASSISTING RESIDENTIAL CUSTOMERS ADEQUATE TO ENSURE THE AFFORDABILITY OF CUSTOMERS ESSENTIAL ELECTRIC NEEDS?

A. No, they are not. Those programs basically are of two types, conservation-oriented programs and programs to help customers pay their winter heating bills. Since there is generally very little that customers can do to reduce essential requirements, conservation programs offer little, if any, potential for relief from the rate increase proposed. The other heating assistance programs only address a limited portion of customers essential needs, and the resouces available for those programs are likely to be quickly consumed if any sizable increase for residential customers is implemented as a result of this case.

Q. HOW SHOULD THE RESIDENTIAL RATE DESIGN BE ADJUSTED IF THE COMMISSION APPROVES LESS THAN THE FULL REVENUE INCREASE REQUESTED BY PECO?

A. As the amount of the overall rate increase is lowered from the level requested by the Company, I recommend that those reductions should be implemented in a manner that provides greater rate relief to the essential electricity requirements of residential customers. This approach to adjusting the residential rate design can offer several potential benefits. First, the burden of the rate increase will be moderated for those electricity requirements that customers are least able to reduce. Second, it will increase the incentives for conservation by those customers who have consumption above the essential use blocks. Third, by reducing the rates for those uses that are least discretionary, it is possible that the Company's uncollectible accounts expenses for the residential class may be held below the levels that might otherwise occur.

Q. HAVE YOU PREPARED A SET OF PROPOSED CHARGES TO IMPLEMENT YOUR ESSENTIAL USE PROPOSALS?

A. The development of a recommended set of charges for implementing these recommendations with respect to essential use blocks for Rates R and RH requires two key inputs. Those two inputs are: (1) a determination by the Commission with respect to the amount of the revenue increase it will allow for the residential class; and (2) bill frequency data from which the amount of residential use which would fall within each of the newly proposed rate blocks can be determined. Naturally, the first of these inputs will not be available until the end of this proceeding. I can, however, produce example calculations that would show the charges that would result under an assumed level of increased revenues for Rates R and RH. The information necessary to determine usage levels for each of the new rate blocks has been just recently provided to me by the Company, under protective order. It is highly voluminous, and I have not as of this time been able to summarize from that data the kWh data by rate block necessary to complete the example rate design calculations for my proposed rate design. Thus, I intend to file a supplemental exhibit, Schedule BRO-8, when the summarization of that data is completed.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes, it does.

BRUCE R. OLIVER

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EDUCATION

1972	M.A., Economics, Virginia Polytechnic Institute and State University
1970	B.A., Economics, Virginia Polytechnic Institute and State University

EXPERIENCE

1985-
Present

Revilo Hill Associates, Inc.
President

Directs the firm's utility and energy consulting practice. Provides expert testimony electric, gas, water and sewer utility rate proceedings on issues relating to utility rates and regulatory policy. Specializes in analyses of cost-of-service, rate design, load research, conservation, load management, utility planning, and natural gas and utility fuel market issues. Projects include:

- Analysis of issues associated with the offering of special rates for commercial and industrial gas customers, including evalauations of proposals for the implementation of flexible interruptible service rates, cogeneration rates, gas transportation service rates, and area development rates;

- Investigation of issues associated with electric and gas utility cost-of-service and rate design issues for intervenors in electric and gas utility rate proceedings.

- Assessment of the costs and benefits of electric utility load management, time-of-day rate, curtailable service programs.

- Evaluation of the load research methods of a major electric utility and assessment of the reasonableness and accuracy with which the Company's estimates of customer class load requirements were developed.

1981-85 Resource Dynamics Corporation
Principal and Vice President

Responsible for the firm's activities in the areas of utility rates and regulatory policy. Directed projects relating to a wide variety of energy and utility issues. Provided expert testimony before utility regulatory commissions on issues relating to rate design, load management, load research, fuel price forecasting, utility costing analyses, and cost allocation methods. Evaluated utility fuel procurement practices, fuel price forecasts, and fuel price forecasting methodologies. Contributed to modeling efforts relating to national and regional estimation of electric utility load curves and coal market prices. Participated in the development and presentation of models and handbooks for cogeneration feasibility assessment and in specific applications of those models.

1980-81 Potomac Electric Power Company
Manager of Rate Research Department

Directed the development of all rate related programs. Supervised the costing, design and analysis of traditional and innovative rates, including time-of-use, load management and cogeneration tariffs. Also responsible for all corporate revenue forecasting activities and all marginal and avoided costing analyses.

1979-80 Pacific Gas and Electric Company
Rate Experimentation Supervisor

Responsible for the design, implementation and analysis of innovative rate programs for both gas and electric service. Developed programs for curtailable service; cogeneration; residential load cycling; and commercial, industrial, and agricultural time-of-use rates. Directed analyses of time-of-use and lifeline price elasticities and participated in the development of marginal and avoided costing methodologies, incremental pricing of gas service and inverted rate structures for gas and electric residential service.

1973-79 ICF Incoporated
Project Manager

Specialized in energy policy and utility regulation. Provided expert testimony on utility rate issues. Designed experimental rate structures for federally funded programs in North Carolina. Provided technical support to the DOE Regulatory Intervention Program. Performed detailed analysis of U.S. petroleum, natural gas, and coal industries. Contributed to the design and development of the National Coal Model, and prepared forecasts of the availability of low sulfur fuels for utility markets.

RATE CASE PARTICIPATION

Pennsylvania

Western Pennsylvania Water Company	Docket No. R-850096
Pennsylvania Power Company	Docket No. R-842740**
Pennsylvania Power & Light Company	Docket No. R-842651
Duquesne Light Company	Docket No. R-842383
UGI Corporation-Gas Utility Division	Docket No. R-832331
Pennsylvania Electric Company	Docket No. R-832550*
Metropolitan Edison Company	Docket No. R-832549*
Pennsylvania Power & Light Company	Docket No. I-830374
Pennsylvania Electric Company	Docket No. R-822250
Metropolitan Edison Company	Docket No. R-822249
Pennsylvania Power & Light Company	Docket No. R-822169
Pennsylvania Gas & Water Company - Water Division	Docket No. R-822102
Columbia Gas Company of Pennsylvania	Docket No. R-822042*
Pennsylvania Gas & Water Company - Gas Division	Docket No. R-821961
Philadelphia Electric Company	Docket No. R-811626

City of Philadelphia

Philadelphia Water Department Water and Wastewater Services	1985 Rate Increase Request

District of Columbia

Potomac Electric Power Company	Formal Case No. 834
Potomac Electric Power Company	Formal Case No. 813
Potomac Electric Power Company	Formal Case No. 813, Phase II
Washington Gas Light Company	Formal Case No. 787
Potomac Electric Power Company	Formal Case No. 785
Potomac Electric Power Company	Formal Case No. 759, Phase I
Potomac Electric Power Company	Formal Case No. 759, Phase II
Potomac Electric Power Company	Formal Case No. 759, Phase III
Potomac Electric Power Company	Formal Case No. 758*

New Jersey

South Jersey Gas Company	Docket No. 843-184, Phase II
Atlantic Electric Company	Docket No. 8310-883, Phase II
New Jersey Natural Gas	Docket No. 831-46
Public Service Electric and Gas	Docket No. 837-620
Public Service Electric and Gas	Docket No. 8210-869

* No testimony submitted
** Testimony submitted but not crossed

Maryland

Potomac Electric Power Company	Formal Case No. 7874
Washington Gas Light Company	Formal Case No. 7649

Virginia

Virginia Electric Power Company	Docket No. PUE 840071
Virginia Electric Power Company	Docket No. PUE 830029
Washington Gas Light Company	Docket No. PUE 830008

City of Alexandria, Virginia

Alexandria Sanitation Authority	1985 Rate Increase Request

Ohio

Toledo Edison Company	Case No. 78-628-EL-FAC

North Carolina

Electric Load Management - Generic Investigation	Docket No. M100, Sub 78

California

Pacific Gas Light Company	Application No.58089

South Dakota

Northern States Power Company	Docket No. F-3188

REPORTS AND PUBLICATIONS

Determinants of Capital Costs for Coal-Fired Power Plants, prepared for U.S. Energy Information Administration, March 1985. (with J. P. Price and C. J. Koravik)

Trends in Electric Utility Load Duration Curves, prepared for U.S. Energy Information Administration, December 1984. (with J. P. Price)

"Potential 1984 Strike by United Mine Workers of America," Executive Briefing Paper, prepared for U.S. Energy INformation Administration, September1984. (with J. P. Price)

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PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

DEVELOPMENT OF PEAK AND AVERAGE ALLOCATION FACTOR

12 Months Ended June 30, 1986

Customer Class	MWh Net Generation	Percent of Net Gen	Load Factor	Weighted % Net Gen	Four Peak Average	Percent of Peak	1 - LF	Weighted % Peak	PEAK & AVERAGE ALLOCATOR
	(1)	(2)	(3)	(4)=(2)*(3)	(5)	(6)	(7)	(8)=(6)*(7)	(9)=(4)+(8)
Rate R	7,084,342	0.23403	0.641	0.14999	1,489,776	0.27630	0.359	0.09922	0.24921
Rate RH	1,754,047	0.05794	0.641	0.03714	211,311	0.03919	0.359	0.01407	0.05121
Rate OP	429,209	0.01418	0.641	0.00909	140	0.00003	0.359	0.00001	0.00910
Total Residential	9,267,598	0.30615	0.641	0.19621	1,701,227	0.31552	0.359	0.11330	0.30951
Rate GS	3,787,866	0.12513	0.641	0.08020	764,118	0.14172	0.359	0.05089	0.13109
Rate PD	2,458,984	0.08123	0.641	0.05206	500,698	0.09286	0.359	0.03335	0.08541
Rate HT	13,320,283	0.44003	0.641	0.28201	2,235,585	0.41462	0.359	0.14889	0.43090
Total Gen. Service	19,567,133	0.64639	0.641	0.41427	3,500,401	0.64920	0.359	0.23313	0.64740
Street Lighting	187,844	0.00621	0.641	0.00398	296	0.00005	0.359	0.00002	0.00400
Septa & Amtrak	720,158	0.02379	0.641	0.01525	97,808	0.01814	0.359	0.00651	0.02176
Other Utilities	462,817	0.01529	0.641	0.00980	80,440	0.01492	0.359	0.00536	0.01516
Interdepartmental	65,953	0.00218	0.641	0.00140	11,714	0.00217	0.359	0.00078	0.00218
TOTAL	30,271,503	1.00000	0.641	0.64090	5,391,886	1.00000	0.359	0.35910	1.00000

Schedule BRO - 1

COST ALLOCATION SUMMARY
Peak and Average Demand Method

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

COST ALLOCATION STUDY
12 Months Ended June 30, 1986

		Commercial and Industrial			Residential						
Classification of Accounts	Total	High Tension	Primary	Secondary	Rate RH	Rate R	Rate OP	Street Lighting	Septa & Amtrak	Other Utilities	Inter-depart-mental
Total Operating Revenue	2,290,779	796,466	181,104	332,517	123,859	714,130	24,477	33,593	49,905	29,889	4,840
Revenue Deductions											
Operation & Maintenace Expenses	1,440,907	546,613	107,353	178,926	83,939	438,627	21,172	16,362	32,065	13,826	2,025
Depreciation & Other Amortization	264,877	101,567	21,335	33,665	14,612	77,000	2,943	4,463	5,241	3,535	516
Taxes Other Than Income	82,178	28,621	6,350	11,297	4,605	26,856	957	1,305	1,674	447	66
Income Taxes	34,032	(11,583)	4,986	23,975	(237)	12,811	(1,170)	1,809	2,040	1,027	374
Provisions for Deferred Income Taxes	27,405	(1,740)	2,611	5,132	303	18,537	(1,036)	1,207	(446)	2,475	364
Investment Tax Credit	(3,401)	(1,266)	(269)	(438)	(192)	(1,028)	(34)	(57)	(66)	(44)	(6)
Total Revenue Deductions	1,845,998	662,212	142,366	252,557	103,030	572,802	22,832	25,089	40,508	21,266	3,338
Operating Income After Income Taxes	444,781	134,254	38,738	79,960	20,829	141,328	1,645	8,504	9,397	8,623	1,502
Rate Base	6,963,532	2,658,955	554,979	901,222	385,674	2,052,241	68,885	97,189	138,648	92,236	13,503
Rates of Return	6.39	5.05	6.98	8.87	5.40	6.89	2.39	8.75	6.78	9.35	11.12
Relative Rate of Return	1.00	0.79	1.09	1.39	0.85	1.08	0.37	1.37	1.06	1.46	1.74

COST ALLOCATION SUMMARY
Revised Distribution System Cost Allocations

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

COST ALLOCATION STUDY
12 Months Ended June 30, 1986

		Commercial and Industrial			Residential						
Classification of Accounts	Total	High Tension	Primary	Secondary	Rate RH	Rate R	Rate OP	Street Lighting	Septa & Amtrak	Other Utilities	Inter-departmental
Total Operating Revenue	2,290,779	796,224	181,215	332,675	123,680	714,533	24,342	33,534	49,851	29,885	4,840
Revenue Deductions											
Operation & Maintenace Expenses	1,440,907	540,280	111,127	185,579	79,459	447,284	17,206	13,778	30,452	13,711	2,032
Depreciation & Other Amortization	264,877	98,523	23,108	36,667	12,397	81,451	1,029	3,277	4,424	3,481	519
Taxes Other Than Income	82,178	28,270	6,572	11,689	4,350	27,341	727	1,147	1,576	440	66
Income Taxes	34,032	(3,635)	223	15,735	5,517	1,518	3,886	5,076	4,175	1,172	365
Provisions for Deferred Income Taxes	27,405	(2,852)	3,393	6,550	(528)	20,037	(1,823)	611	(799)	2,451	366
Investment Tax Credit	(3,401)	(1,232)	(292)	(477)	(167)	(1,075)	(11)	(41)	(56)	(43)	(7)
Total Revenue Deductions	1,845,998	659,354	144,130	255,743	101,028	576,555	21,014	23,849	39,772	21,212	3,342
Operating Income After Income Taxes	444,781	136,870	37,084	76,932	22,652	137,978	3,328	9,685	10,080	8,673	1,498
Rate Base	6,963,532	2,583,711	600,456	978,535	329,855	2,162,961	20,246	65,808	117,524	90,849	13,586
Rate of Return	6.39	5.30	6.18	7.86	6.87	6.38	16.44	14.72	8.58	9.55	11.03
Relative Rate of Return	1.00	0.83	0.97	1.23	1.08	1.00	2.57	2.30	1.34	1.49	1.73

COMPOSITE OF OCA COST ALLOCATION CHANGES
Peak and Average
Revised Secondary Demands
Revised Primary Customer Component
Revised Rent on Electric Property

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

COST ALLOCATION STUDY
12 Months Ended June 30, 1986

Classification of Accounts	Total	Commercial and Industrial: High Tension	Commercial and Industrial: Primary	Commercial and Industrial: Secondary	Residential: Rate RH	Residential: Rate R	Residential: Rate OP	Street Lighting	Septa & Amtrak	Other Utilities	Inter-depart-mental
Total Operating Revenue	2,290,779	792,704	180,503	332,461	124,297	717,655	24,541	34,376	49,690	29,731	4,821
Revenue Deductions											
Operation & Maintenace Expenses	1,440,907	548,161	107,524	180,441	85,272	434,186	21,592	15,684	32,188	13,826	2,034
Depreciation & Other Amortization	264,877	102,230	21,411	34,247	15,133	75,284	3,094	4,175	5,248	3,535	520
Taxes Other Than Income	82,178	28,728	6,362	11,390	4,688	26,579	982	1,258	1,678	447	67
Income Taxes	34,032	(15,370)	4,476	22,185	(1,597)	19,720	(1,610)	3,050	1,872	951	354
Provisions for Deferred Income Taxes	27,405	(1,262)	2,665	5,512	646	17,390	(937)	996	(446)	2,475	366
Investment Tax Credit	(3,401)	(1,278)	(271)	(447)	(201)	(999)	(37)	(52)	(66)	(44)	(7)
Total Revenue Deductions	1,845,998	661,209	142,166	253,327	103,942	572,160	23,084	25,112	40,474	21,190	3,334
Operating Income After Income Taxes	444,781	131,494	38,337	79,134	20,355	145,495	1,457	9,264	9,216	8,541	1,488
Rate Base	6,963,532	2,678,280	557,138	916,767	399,697	2,005,583	72,951	88,722	138,560	92,226	13,609
Rate of Return	6.39	4.91	6.88	8.63	5.09	7.25	2.00	10.44	6.65	9.26	10.93
Relative Rate of Return	1.00	0.77	1.08	1.35	0.80	1.14	0.31	1.63	1.04	1.45	1.71

PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

CUSTOMER CLASS RATES OF RETURN

AT PECO'S PROPOSED RATES

USING OCA'S RECOMMENDED COST ALLOCATIONS

Rate Class	Rate of Return	Percent of System Average Rate of Return
Rate R	13.88	109
Rate RH	10.86	85
Off Peak	4.00	31
Residential	13.10	103
Secondary	15.60	123
Primary	13.52	106
High Tension	11.48	90
General Service	12.66	100
Street Lighting	11.16	88
Septa & Amtrak	10.10	80

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

OCA PROPOSED ADJUSTMENTS TO THE DISTRIBUTION
OF THE REVENUE INCREASE BY CLASS
($1,000's)

Rate Class	PECO'S Proposed Increase*	OCA Proposed Adjustment	OCA Proposed Increase
Rate R	270,054	(7,450)	262,604
Rate RH	46,791	0	46,791
Rate OP	2,967	7,450	10,417
Residential	319,812	0	319,812
Rate GS	129,762	(10,076)	119,686
Rate PD	75,129	0	75,129
Rate HT	357,255	0	357,255
General Service	562,146	(10,076)	552,070
Street Lighting	1,301	2,763	4,064
Septa & Amtrak	9,712	7,313	17,025
Other Utilities	3	0	3
TOTAL	892,974	(0)	892,974

* From PECO's response to IR-PBUUG-1-2, Col. 3

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

PROOF OF REVENUES
FOR OCA RECOMMENDED RATE DESIGNS

Rates R and RH

Rate Block	Billing Determinants	Present Rates	Revenue	Proposed Rates	Revenue	Percent Increase
RATE R						
Number of Bills	6,450,456	$ 4.5000	29,027,052	$ 4.7500	30,639,666	5.6
Up to 500 KWH	2,382,086,933	0.1035	246,545,998	0.1345	320,390,692	30.0
KWH Over 500 - Winter	399,375,288	0.1035	41,335,342	0.1345	53,715,976	30.0
KWH Over 500 - Summer	380,388,453	0.1180	44,885,837	0.1564	59,492,754	32.5
Subtotal	3,161,850,674		361,794,229		464,239,089	28.3
Unaccounted			7,059		9,058	28.3
Base Revenue			361,801,288		464,248,147	28.3
12 Mos. Ended 6/30/86 Pro Forma Base Revenue			739,467,000		948,852,852	28.3
RATE RH						
Number of Bills	372,768	$ 4.5000	1,677,456	$ 4.7500	1,770,648	5.6
Up to 500 KWH	176,144,091	0.1035	18,230,913	0.1345	23,691,380	30.0
KWH Over 500 - Winter	296,275,236	0.0593	17,569,121	0.0745	22,074,756	25.6
KWH Over 500 - Summer	66,620,779	0.1180	7,861,252	0.1564	10,419,490	32.5
Subtotal	539,040,106		45,338,743		57,956,274	27.8
Unaccounted			(216)		(276)	27.8
Base Revenue			45,338,527		57,955,998	27.8
12 Mos. Ended 6/30/86 Pro Forma Base Revenue			127,424,000		162,885,421	27.8
TOTAL RATES R AND RH			866,891,000		1,111,738,273	28.2
REVENUE TARGET					1,111,700,000	

R-850152

OCP

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PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

EXAMPLE ESSENTIAL USE RATE DESIGN

Scenario I: Half of Full Increase for Rates R and RH*

MONTHLY CUSTOMER CHARGE $4.7500

MONTHLY ENERGY CHARGES ($/kWh)

	Essential Use					Excess Use	
	0 - 350 kWh	351 - 500 kWh	501 - 700 kWh	701 - 1050 kWh	1050 - 1400 kWh	351 - 500 kWh	All Other kWh
Basic Use Customers							
Winter Months	$0.1102	NA	NA	NA	NA	$0.1345	$0.1345
Summer Months	$0.1102	NA	NA	NA	NA	$0.1345	$0.1564
Water Heating Customers							
Winter Months	$0.1102	$0.1102	$0.1102	NA	NA	NA	$0.1345
Summer Months	$0.1102	$0.1102	$0.1257	NA	NA	NA	$0.1564
Space Heating Customers							
Winter Months	$0.1102	$0.1102	$0.0633	$0.0633	NA	NA	$0.0745
Summer Months	$0.1102	NA	NA	NA	NA	$0.1345	$0.1564
Water Heating & Space Heating Customers							
Winter Months	$0.1102	$0.1102	$0.0633	$0.0633	$0.0633	NA	$0.0745
Summer Months	$0.1102	$0.1102	$0.1257	NA	NA	NA	$0.1564

* Assumes no phase-in. Increase granted is implemented immediately.

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

PROOF OF REVENUES
FOR OCA RECOMMENDED RATE DESIGNS

Scenario 1: Half of Full Increase for Rates R and RH

Rate Block	Billing Determinants	Present Rates	Revenue	Proposed Rates	Revenue	Percent Increase
RATE R						
Number of Bills	6,450,456	$ 4.5000	29,027,052	$ 4.7500	30,639,666	5.6
Essential Use						
Basic Use						
Up to 350 KWH - R	1,854,687,592	0.1035	191,960,166	0.1102	204,386,573	6.5
Up to 350 KWH - RM						
Winter	2,640,294	0.1035	273,270	0.1102	290,960	6.5
Summer	1,681,326	0.1180	198,396	0.1257	211,343	6.5
Water Heating Use						
Next 350 KWH - Winter						
351 - 500 KWH	103,750,631	0.1035	10,738,190	0.1102	11,433,320	6.5
501 - 700 KWH	78,040,300	0.1035	8,077,171	0.1102	8,600,041	6.5
Next 350 KWH - Summer						
351 - 500 KWH	51,801,741	0.1035	5,361,480	0.1102	5,708,552	6.5
501 - 700 KWH	40,937,137	0.1180	4,830,582	0.1257	5,145,798	6.5
Excess Use						
351 - 500 KWH						
Winter	226,776,513	0.1035	23,471,369	0.1345	30,501,441	30.0
Summer	145,070,457	0.1035	15,014,792	0.1345	19,511,976	30.0
All Other						
Winter	318,694,694	0.1035	32,984,901	0.1345	42,864,436	30.0
Summer	337,769,990	0.1180	39,856,859	0.1564	52,827,226	32.5
TOTAL RATE R	3,161,850,674		361,794,229		412,121,332	13.9
Unaccounted			7,059		8,041	13.9
Base Revenue			361,801,288		412,129,373	13.9
12 Mos. Ended 6/30/86 Pro Forma Base Revenue			739,467,000		842,329,978	13.9

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

PROOF OF REVENUES
FOR ESSENTIAL USE RATE DESIGN

Scenario 1: Half of Full Increase for Rates R and RH

Rate Block	Billing Determinants	Present Rates	Revenue	Proposed Rates	Revenue	Percent Increase
RATE RH						
Number of Bills	372,768	$ 4.5000	1,677,456	$ 4.7500	1,770,648	5.6
Essential Use						
Basic Use						
Up to 350 KWH	144,221,359	0.1035	14,926,911	0.1102	15,893,194	6.5
Water Heating Use						
Next 350 KWH - Winter						
351 - 500 KWH	14,522,112	0.1035	1,503,039	0.1102	1,600,337	6.5
501 - 700 KWH	14,178,552	0.0593	840,788	0.0633	897,502	6.7
Next 350 KWH - Summer						
351 - 500 KWH	6,820,172	0.1035	705,888	0.1102	751,583	6.5
501 - 700 KWH	6,937,831	0.1180	818,664	0.1257	872,085	6.5
Space Heating Use						
Next 700 KWH - Winter	113,991,729	0.0593	6,759,710	0.0633	7,215,676	6.7
Excess Use						
351 - 500 KWH						
Summer	10,580,448	0.1035	1,095,076	0.1345	1,423,070	30.0
All Other						
Winter	168,104,955	0.0593	9,968,624	0.0745	12,523,819	25.6
Summer	59,682,948	0.1180	7,042,588	0.1564	9,334,413	32.5
TOTAL RATE RH	539,040,106		45,338,743		52,282,328	15.3
	66,620,779	0.1180				
Unaccounted	296,275,236	0.0593	(216)		(249)	15.3
	176,144,091	0.1035				
Base Revenue			45,338,527		52,282,079	15.3
12 Mos. Ended 6/30/86 Pro Forma Base Revene			127,424,000		146,938,864	15.3
TOTAL Rates R and RH			866,891,000		989,268,842	14.1
Revenue Target					989,270,500	

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

EXAMPLE ESSENTIAL USE RATE DESIGN

Scenario 2: One-Third of Full Increase for Rates R and RH*

MONTHLY CUSTOMER CHARGE $4.7000

MONTHLY ENERGY CHARGES ($/kWh)

	Essential Use					Excess Use	
	0 - 350 kWh	351 - 500 kWh	501 - 700 kWh	701 - 1050 kWh	1050 - 1400 kWh	351 - 500 kWh	All Other kWh
Basic Use Customers							
Winter Months	$0.1076	NA	NA	NA	NA	$0.1244	$0.1244
Summer Months	$0.1076	NA	NA	NA	NA	$0.1244	$0.1447
Water Heating Customers							
Winter Months	$0.1076	$0.1076	$0.1076	NA	NA	NA	$0.1244
Summer Months	$0.1076	$0.1076	$0.1227	NA	NA	NA	$0.1447
Space Heating Customers							
Winter Months	$0.1076	$0.1076	$0.0617	$0.0617	NA	NA	$0.0697
Summer Months	$0.1076	NA	NA	NA	NA	$0.1244	$0.1447
Water Heating & Space Heating Customers							
Winter Months	$0.1076	$0.1076	$0.0617	$0.0617	$0.0617	NA	$0.0697
Summer Months	$0.1076	$0.1076	$0.1227	NA	NA	NA	$0.1447

* Assumes no phase-in. Increase granted is implemented immediately.

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

PROOF OF REVENUES
FOR OCA RECOMMENDED RATE DESIGNS

Scenario 2: One-Third of Full Increase for Rates R and RH

Rate Block	Billing Determinants	Present Rates	Revenue	Proposed Rates	Revenue	Percent Increase
RATE R						
Number of Bills	6,450,456	$ 4.5000	29,027,052	$ 4.7000	30,317,143	4.4
Essential Use						
Basic Use						
Up to 350 KWH - R	1,854,687,592	0.1035	191,960,166	0.1076	199,564,385	4.0
Up to 350 KWH - RH						
Winter	2,640,294	0.1035	273,270	0.1076	284,096	4.0
Summer	1,681,326	0.1180	198,396	0.1227	206,299	4.0
Water Heating Use						
Next 350 KWH - Winter						
351 - 500 KWH	103,750,631	0.1035	10,738,190	0.1076	11,163,568	4.0
501 - 700 KWH	78,040,300	0.1035	8,077,171	0.1076	8,397,136	4.0
Next 350 KWH - Summer						
351 - 500 KWH	51,801,741	0.1035	5,361,480	0.1076	5,573,867	4.0
501 - 700 KWH	40,937,137	0.1180	4,830,582	0.1227	5,022,987	4.0
Excess Use						
351 - 500 KWH						
Winter	226,776,513	0.1035	23,471,369	0.1244	28,210,998	20.2
Summer	145,070,457	0.1035	15,014,792	0.1244	18,046,765	20.2
All Other						
Winter	318,694,694	0.1035	32,984,901	0.1244	39,645,620	20.2
Summer	337,769,990	0.1180	39,856,859	0.1447	48,875,317	22.6
TOTAL RATE R	3,161,850,674		361,794,229		395,308,181	9.3
Unaccounted			7,059		7,713	9.3
Base Revenue			361,801,288		395,315,894	9.3
12 Mos. Ended 6/30/86 Pro Forma Base Revenue			739,467,000		807,965,775	9.3

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

PROOF OF REVENUES
FOR OCA RECOMMENDED RATE DESIGNS

Scenario 2: One-Third of Full Increase for Rates R and RH

Rate Block	Billing Determinants	Present Rates	Revenue	Proposed Rates	Revenue	Percent Increase
RATE RH						
Number of Bills	372,768	$ 4.5000	1,677,456	$ 4.7000	1,752,010	4.4
Essential Use						
Basic Use						
Up to 350 KWH	144,221,359	0.1035	14,926,911	0.1076	15,518,218	4.0
Water Heating Use						
Next 350 KWH - Winter						
351 - 500 KWH	14,522,112	0.1035	1,503,039	0.1076	1,562,579	4.0
501 - 700 KWH	14,178,552	0.0593	840,788	0.0617	874,817	4.0
Next 350 KWH - Summer						
351 - 500 KWH	6,820,172	0.1035	705,888	0.1076	733,851	4.0
501 - 700 KWH	6,937,831	0.1180	818,664	0.1227	851,272	4.0
Space Heating Use						
Next 700 KWH - Winter	113,991,729	0.0593	6,759,710	0.0617	7,033,290	4.0
Excess Use						
351 - 500 KWH						
Summer	10,580,448	0.1035	1,095,076	0.1244	1,316,208	20.2
All Other						
Winter	168,104,955	0.0593	9,968,624	0.0697	11,716,915	17.5
Summer	59,682,948	0.1180	7,042,588	0.1447	8,636,123	22.6
TOTAL RATE RH	539,040,106		45,338,743		49,995,281	10.3
	66,620,779	0.1180				
Unaccounted	296,275,236	0.0593	(216)		(238)	10.3
	176,144,091	0.1035				
Base Revenue			45,338,527		49,995,043	10.3
12 Mos. Ended 6/30/86 Pro Forma Base Revenue			127,424,000		140,511,147	10.3
TOTAL RATES R AND RH			866,891,000		948,476,921	9.4
Revenue Target					948,477,000	

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

EXAMPLE ESSENTIAL USE RATE DESIGN

Scenario 3: Half of Full Increase for Rates R and RH Phased-In Over Two Years*

MONTHLY CUSTOMER CHARGE $4.7500

MONTHLY ENERGY CHARGES ($/kWh)

	Essential Use					Excess Use	
	0 - 350 kWh	351 - 500 kWh	501 - 700 kWh	701 - 1050 kWh	1050 - 1400 kWh	351 - 500 kWh	All Other kWh
Basic Use Customers							
Winter Months	$0.1119	NA	NA	NA	NA	$0.1313	$0.1313
Summer Months	$0.1119	NA	NA	NA	NA	$0.1313	$0.1527
Water Heating Customers							
Winter Months	$0.1119	$0.1119	$0.1119	NA	NA	NA	$0.1313
Summer Months	$0.1119	$0.1119	$0.1276	NA	NA	NA	$0.1527
Space Heating Customers							
Winter Months	$0.1119	$0.1119	$0.0641	$0.0641	NA	NA	$0.0729
Summer Months	$0.1119	NA	NA	NA	NA	$0.1313	$0.1527
Water Heating & Space Heating Customers							
Winter Months	$0.1119	$0.1119	$0.0641	$0.0641	$0.0641	NA	$0.0729
Summer Months	$0.1119	$0.1119	$0.1276	NA	NA	NA	$0.1527

* Rates to be effective at completion of two-year phase-in of rate increase.

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

PROOF OF REVENUES
FOR OCA RECOMMENDED RATE DESIGNS

Scenario 3: Half of Full Increase for Rates R and RH
Phased-In Over Two Years

Rate Block	Billing Determinants	Present Rates	Revenue	Proposed Rates	Revenue	Percent Increase
RATE R						
Number of Bills	6,450,456	$ 4.5000	29,027,052	$ 4.7500	30,639,666	5.6
Essential Use						
Basic Use						
Up to 350 KWH - R	1,854,687,592	0.1035	191,960,166	0.1119	207,539,541	8.1
Up to 350 KWH - RH						
Winter	2,640,294	0.1035	273,270	0.1119	295,449	8.1
Summer	1,681,326	0.1180	198,396	0.1276	214,537	8.1
Water Heating Use						
Next 350 KWH - Winter						
351 - 500 KWH	103,750,631	0.1035	10,738,190	0.1119	11,609,696	8.1
501 - 700 KWH	78,040,300	0.1035	8,077,171	0.1119	8,732,710	8.1
Next 350 KWH - Summer						
351 - 500 KWH	51,801,741	0.1035	5,361,480	0.1119	5,796,615	8.1
501 - 700 KWH	40,937,137	0.1180	4,830,582	0.1276	5,223,579	8.1
Excess Use						
351 - 500 KWH						
Winter	226,776,513	0.1035	23,471,369	0.1313	29,775,756	26.9
Summer	145,070,457	0.1035	15,014,792	0.1313	19,047,751	26.9
All Other						
Winter	318,694,694	0.1035	32,984,901	0.1313	41,844,613	26.9
Summer	337,769,990	0.1180	39,856,859	0.1527	51,577,477	29.4
TOTAL RATE R	3,161,850,674		361,794,229		412,297,390	14.0
Unaccounted			7,059		8,044	14.0
Base Revenue			361,801,288		412,305,435	14.0
12 Mos. Ended 6/30/86 Pro Forma Base Revenue			739,467,000		842,689,821	14.0

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

PROOF OF REVENUES
FOR ESSENTIAL USE RATE DESIGN

Scenario 3: Half of Full Increase for Rates R and RH
Phased-In Over Two Years

Rate Block	Billing Determinants	Present Rates	Revenue	Proposed Rates	Revenue	Percent Increase
RATE RH						
Number of Bills	372,768	$ 4.5000	1,677,456	$ 4.7500	1,770,648	5.6
Essential Use						
Basic Use						
Up to 350 KWH	144,221,359	0.1035	14,926,911	0.1119	16,138,370	8.1
Water Heating Use						
Next 350 KWH - Winter						
351 - 500 KWH	14,522,112	0.1035	1,503,039	0.1119	1,625,024	8.1
501 - 700 KWH	14,178,552	0.0593	840,788	0.0641	908,845	8.1
Next 350 KWH - Summer						
351 - 500 KWH	6,820,172	0.1035	705,888	0.1119	763,177	8.1
501 - 700 KWH	6,937,831	0.1180	818,664	0.1276	885,267	8.1
Space Heating Use						
Next 700 KWH - Winter	113,991,729	0.0593	6,759,710	0.0641	7,306,870	8.1
Excess Use						
351 - 500 KWH						
Summer	10,580,448	0.1035	1,095,076	0.1313	1,389,213	26.9
All Other						
Winter	168,104,955	0.0593	9,968,624	0.0729	12,254,851	22.9
Summer	59,682,948	0.1180	7,042,588	0.1527	9,113,586	29.4
TOTAL RATE RH	539,040,106		45,338,743		52,155,852	15.0
	66,620,779	0.1180				
Unaccounted	296,275,236	0.0593	(216)		(248)	15.0
	176,144,091	0.1035				
Base Revenue			45,338,527		52,155,604	15.0
12 Mos. Ended 6/30/86 Pro Forma Base Revenue			127,424,000		146,583,405	15.0
TOTAL RATES R AND RH			866,891,000		989,273,225	14.1
Revenue Target					989,270,500	

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

MONTHLY BILL COMPARISONS FOR
EXAMPLE ESSENTIAL USE RATE DESIGN

Scenario 1: Half of Full Increase for Rates R and RH*

	Winter Months				Summer Months			
Monthly kWh Use	Company Rates	Essential Use Rate	Dollar Increase	Percent Increase	Company Rates	Essential Use Rate	Dollar Increase	Percent Increase
			(Basic Use Customer)					
0	5.03	5.03	0.00	0.0	5.03	5.03	.00	.0
50	12.11	10.74	-1.38	-11.4	12.11	10.74	-1.38	-11.4
100	19.19	16.44	-2.75	-14.3	19.20	16.44	-2.75	-14.3
150	26.28	22.15	-4.13	-15.7	26.28	22.15	-4.13	-15.7
200	33.36	27.86	-5.50	-16.5	33.36	27.86	-5.51	-16.5
250	40.44	33.56	-6.88	-17.0	40.45	33.56	-6.88	-17.0
300	47.53	39.27	-8.26	-17.4	47.53	39.27	-8.26	-17.4
350	54.61	44.98	-9.63	-17.6	54.61	44.98	-9.64	-17.6
400	61.69	51.97	-9.72	-15.8	61.70	51.97	-9.73	-15.8
450	68.78	58.96	-9.81	-14.3	68.78	58.96	-9.82	-14.3
500	75.86	65.96	-9.90	-13.1	75.86	65.96	-9.91	-13.1
600	90.03	79.94	-10.08	-11.2	92.19	82.26	-9.93	-10.8
700	104.19	93.93	-10.26	-9.9	108.51	98.57	-9.95	-9.2
800	118.36	107.92	-10.44	-8.8	124.84	114.87	-9.97	-8.0
900	132.53	121.90	-10.62	-8.0	141.17	131.18	-9.99	-7.1
1,000	146.69	135.89	-10.80	-7.4	157.49	147.48	-10.01	-6.4
1,050	153.78	142.88	-10.89	-7.1	165.65	155.63	-10.02	-6.0
1,100	160.86	149.88	-10.98	-6.8	173.82	163.79	-10.03	-5.8
1,200	175.03	163.86	-11.16	-6.4	190.14	180.09	-10.05	-5.3
1,300	189.19	177.85	-11.34	-6.0	206.47	196.40	-10.07	-4.9
1,400	203.36	191.84	-11.52	-5.7	222.80	212.70	-10.10	-4.5
1,500	217.52	205.82	-11.70	-5.4	239.12	229.00	-10.12	-4.2
1,750	252.94	240.79	-12.15	-4.8	279.94	269.77	-10.17	-3.6
2,000	288.36	275.75	-12.60	-4.4	320.75	310.53	-10.22	-3.2
2,500	359.19	345.69	-13.50	-3.8	402.38	392.05	-10.33	-2.6
3,000	430.02	415.62	-14.40	-3.3	484.01	473.58	-10.43	-2.2
4,000	571.68	555.48	-16.20	-2.8	647.27	636.62	-10.65	-1.6
5,000	713.35	695.35	-18.00	-2.5	810.53	799.67	-10.86	-1.3

* Assumes no phase-in. Increase granted is implemented immediately.

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

MONTHLY BILL COMPARISONS FOR
EXAMPLE ESSENTIAL USE RATE DESIGN

Scenario 3: Half of Full Increase for Rates R and RH
Phased-In Over Two Years*

	Winter Months				Summer Months			
Monthly kWh Use	Company Rates	Essential Use Rate	Dollar Increase	Percent Increase	Company Rates	Essential Use Rate	Dollar Increase	Percent Increase
			(Basic Use Customer)					
0	5.03	5.03	0.00	0.0	5.03	5.03	.00	.0
50	12.11	10.83	-1.29	-10.6	12.11	10.83	-1.29	-10.6
100	19.19	16.62	-2.57	-13.4	19.20	16.62	-2.57	-13.4
150	26.28	22.42	-3.86	-14.7	26.28	22.42	-3.86	-14.7
200	33.36	28.22	-5.14	-15.4	33.36	28.22	-5.15	-15.4
250	40.44	34.01	-6.43	-15.9	40.45	34.01	-6.43	-15.9
300	47.53	39.81	-7.72	-16.2	47.53	39.81	-7.72	-16.2
350	54.61	45.61	-9.00	-16.5	54.61	45.61	-9.01	-16.5
400	61.69	52.43	-9.26	-15.0	61.70	52.43	-9.26	-15.0
450	68.78	59.26	-9.52	-13.8	68.78	59.26	-9.52	-13.8
500	75.86	66.08	-9.78	-12.9	75.86	66.08	-9.78	-12.9
600	90.03	79.73	-10.30	-11.4	92.19	81.99	-10.20	-11.1
700	104.19	93.37	-10.82	-10.4	108.51	97.91	-10.61	-9.8
800	118.36	107.02	-11.34	-9.6	124.84	113.82	-11.02	-8.8
900	132.53	120.67	-11.86	-8.9	141.17	129.73	-11.43	-8.1
1,000	146.69	134.32	-12.38	-8.4	157.49	145.64	-11.85	-7.5
1,050	153.78	141.14	-12.63	-8.2	165.65	153.60	-12.05	-7.3
1,100	160.86	147.96	-12.89	-8.0	173.82	161.56	-12.26	-7.1
1,200	175.03	161.61	-13.41	-7.7	190.14	177.47	-12.67	-6.7
1,300	189.19	175.26	-13.93	-7.4	206.47	193.38	-13.09	-6.3
1,400	203.36	188.91	-14.45	-7.1	222.80	209.30	-13.50	-6.1
1,500	217.52	202.56	-14.97	-6.9	239.12	225.21	-13.91	-5.8
1,750	252.94	236.67	-16.27	-6.4	279.94	264.99	-14.94	-5.3
2,000	288.36	270.79	-17.56	-6.1	320.75	304.78	-15.98	-5.0
2,500	359.19	339.03	-20.16	-5.6	402.38	384.34	-18.04	-4.5
3,000	430.02	407.27	-22.75	-5.3	484.01	463.91	-20.10	-4.2
4,000	571.68	543.75	-27.94	-4.9	647.27	623.04	-24.23	-3.7
5,000	713.35	680.22	-33.12	-4.6	810.53	782.17	-28.36	-3.5

* Rates to be effective at completion of two-year phase-in of rate increase.

CHECKED		
TYPED		
COMPARED AND FOOTED		

Comparison of Proposed Rates

	PECo	Wirtshafter Proposed Rate	Differe
Feb '85	$ 1 194 615.57	$ 1 186 509.81	8 105
Mar	1 251 889.32	1 277 752.44	- 25 863
Apr	1 247 310.57	1 309 704.73	- 62 393
May	1 391 557.47	1 447 320.03	- 55 762
Jun	1 493 725.44	1 603 557.12	- 109 831
Jul	1 502 886.75	1 587 724.35	- 84 83
Aug	1 565 692.59	1 661 214.99	- 95 52
Sep	1 658 395.32	1 724 467.56	- 66 072
Oct	1 692 880.89	1 789 969.29	- 97 088
Nov	1 410 955.86	1 460 366.58	- 49 410
Dec	1 381 404.37	1 452 603.66	- 71 199
Jan '86	1 277 180.62	1 239 387.03	37 793
	$ 17 068 494.77	$ 17 740 577.19	$ 672 082

COMPARISON OF PE Co PROPOSED RATE Vs.
WIRTSHAFTER PROPOSED RATE

	BILLING UNITS	PE Co PROPOSED RATE	BILL
CUSTOMER CHARGE		$ 264.15	$ 264.1
BILLING DEMAND	34488	$ 9.44	325,566.7
ENERGY CHARGES:			
150 HRS USE OF DMD	5,173,200	$ 0.0964	498,696.48
" " " " "	5,173,200	0.0668	345,569.76
ADDITIONAL USE	6,422,900	0.0375	240,858.75

TOTAL BASE BILL $ 1,410,955

	WIRTSHAFTER PROPOSED RATE	BILL
CUSTOMER CHARGE	$ 264.15	$ 26
BILLING DEMAND	$ 5.77	198,995.
ENERGY CHARGES		
150 HRS USE OF DMD	$ 0.0940	486,280.
" " " " "	0.0764	395,232.
ADDITIONAL USE	0.0591	379,593.3

TOTAL BASE BILL $ 1,460,366

DIFFERENCE $ 49,410

ARISON OF PECO PROPOSED RATE
SHAFTER PROPOSED RATE
LOW LOAD FACTOR CUSTOMER
(30,000 KW, 150 HOURS' USE)

	BILLING UNITS	PECO RATE	BILL
CHG		$264.15	$26
DEMAND CHG	30,000	$9.44	$283,20
OURS' USE	4,500,000	$0.0964	433,80
BASE BILL			$717,26

		WIRTSHAFTER RATE	BILL
CHG		$264.15	$26
DEMAND CHG	30,000	$5.77	173,10
HOURS' USE	4,500,000	$0.0940	423,00
BASE BILL			$596,36
ENCE			$120,90

OMPARISON OF PECO PROPOSED RATE HT TO ...
WIRTSHAFTER PROPOSED RATE
HIGH LOAD FACTOR CUSTOMER
(30,000 KW, 520 HOURS' USE)

	BILLING UNITS	PECO RATE	BILL
TOMER CHG		$264.15	$26
ING DEMAND	30,000	$9.44	283,20
RGY CHG			
50 HRS USE	4,500,000	$0.0964	433,80
50 HRS USE	4,500,000	0.0668	300,60
DDITIONAL	6,600,000	0.0375	247,50
BASE BILL			$1,265,36

		WIRTSHAFTER RATE	BILL
TOMER CHG		$264.15	$ 26
ING DEMAND	30,000	$5.77	173,10
RGY CHG			
50 HRS USE	4,500,000	$0.0940	423,0
50 HRS USE	4,500,000	0.0764	343,8
DDITIONAL	6,600,000	0.0591	390,0
L BASE BILL			$1,330,22
ERENCE			$64,8

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SECRETARY'S OFFICE
Public Utility Commission

COMMONWEALTH OF PENNSYLVANIA
BEFORE THE PUBLIC UTILITIES COMMISSION

THE PENNSYLVANIA PUBLIC UTILITIES COMMISSION V. PHILADELPHIA ELECTRIC COMPANY	Docket No. R-850152

2-21-86

UP/UUC STATEMENT #2

Phila PD

TESTIMONY OF DR. S.L. FELDMAN
ON BEHALF OF THE
UTILITY USERS COMMITTEE/
UNIVERSITY OF PENNSYLVANIA

RDS

DOCKETED
FEB 2 6 1986

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

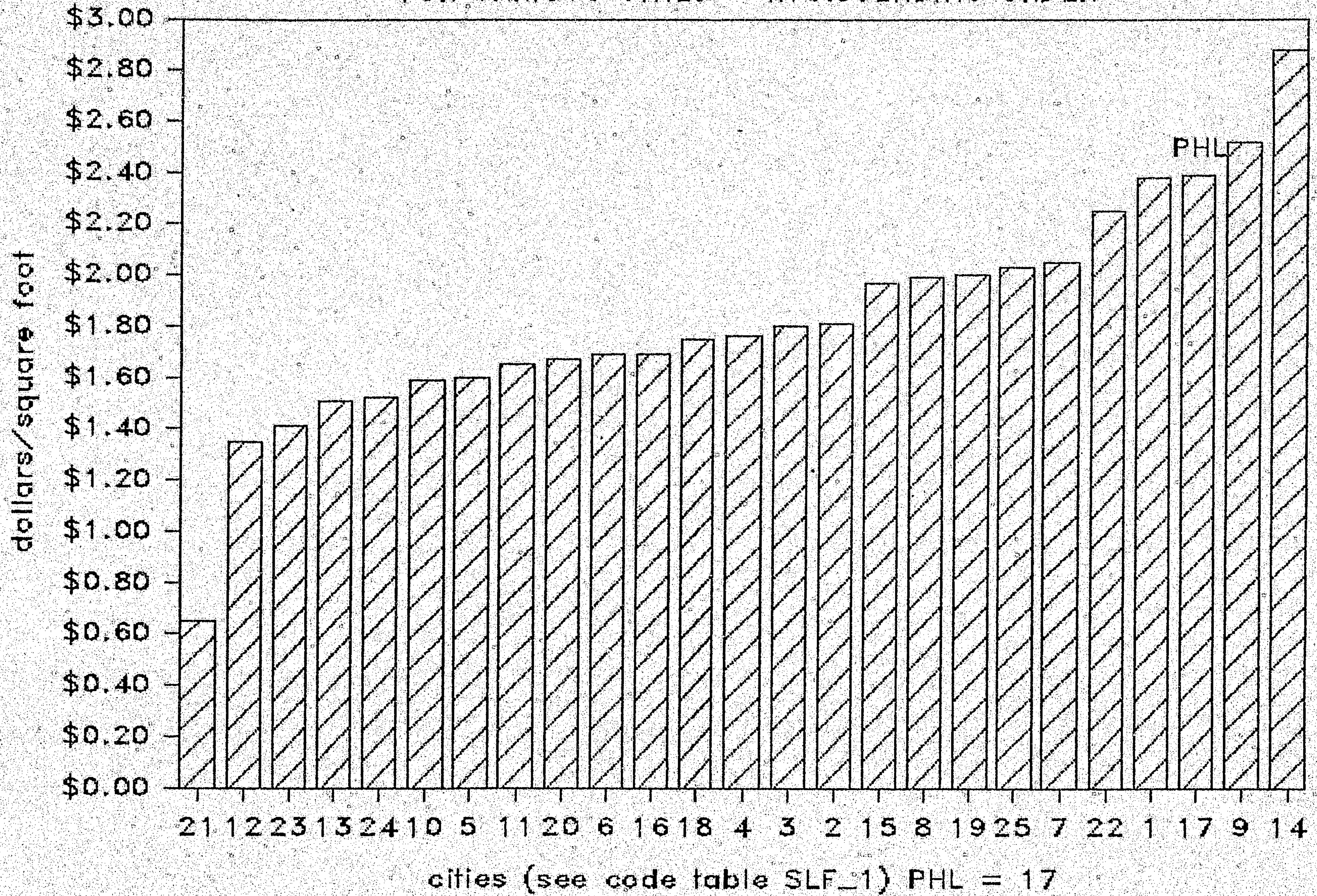
ECONOMIC COMPARISON OF UTILITY COSTS AND TOTAL OPERATING EXPENSES FOR COMMERCIAL OFFICE BUILDINGS IN VARIOUS U.S. CITIES

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

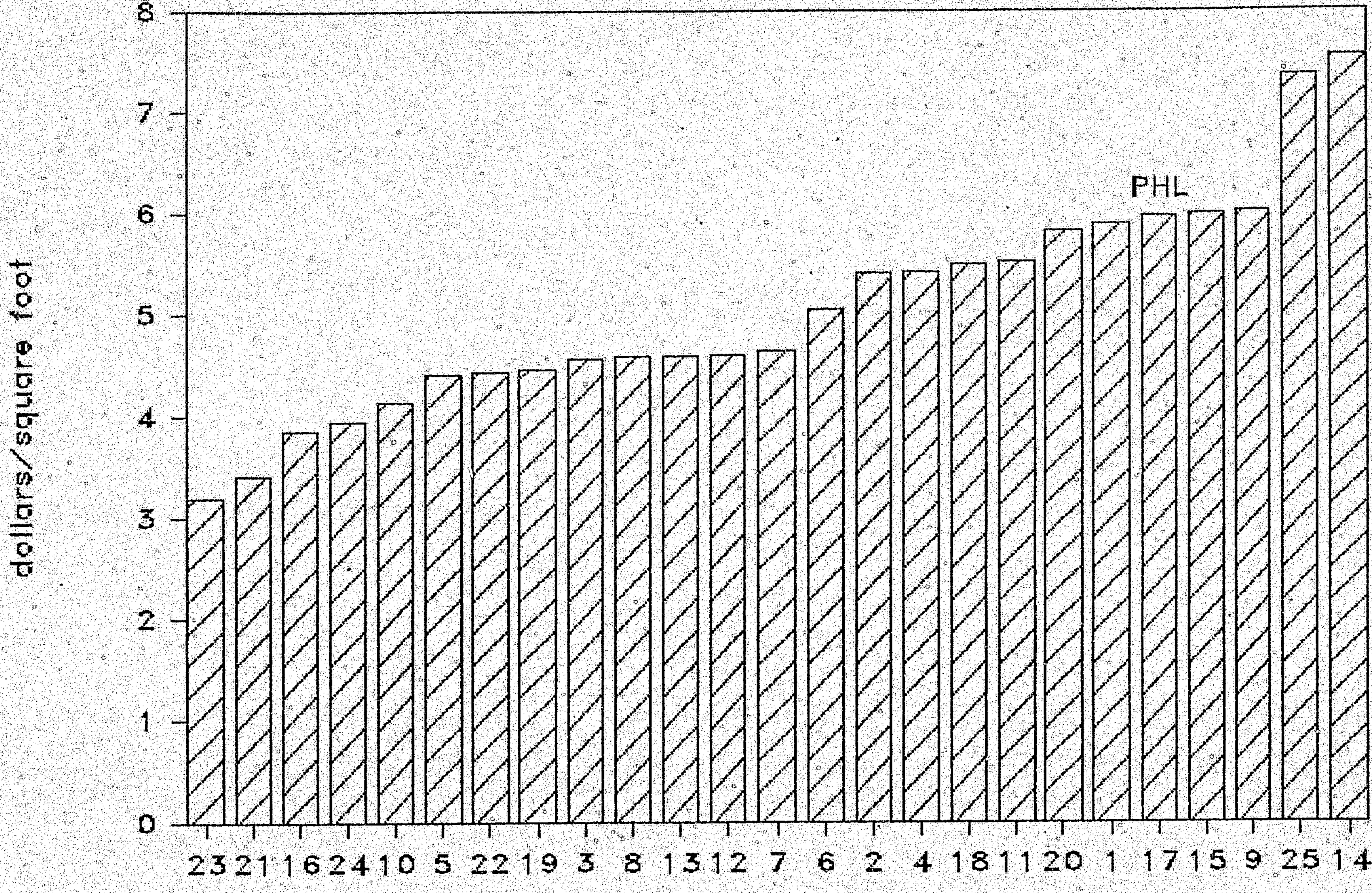


urce: 1985 BOMA Experience
Exchange Report

FIGURE SLF_1

TOTAL OPERATING EXPENSES

FOR VARIOUS CITIES — IN ASCENDING ORDER



urce: 1985 BOMA Experience Exchange Report

FIGURE SLF_2

TABLE SLF__3

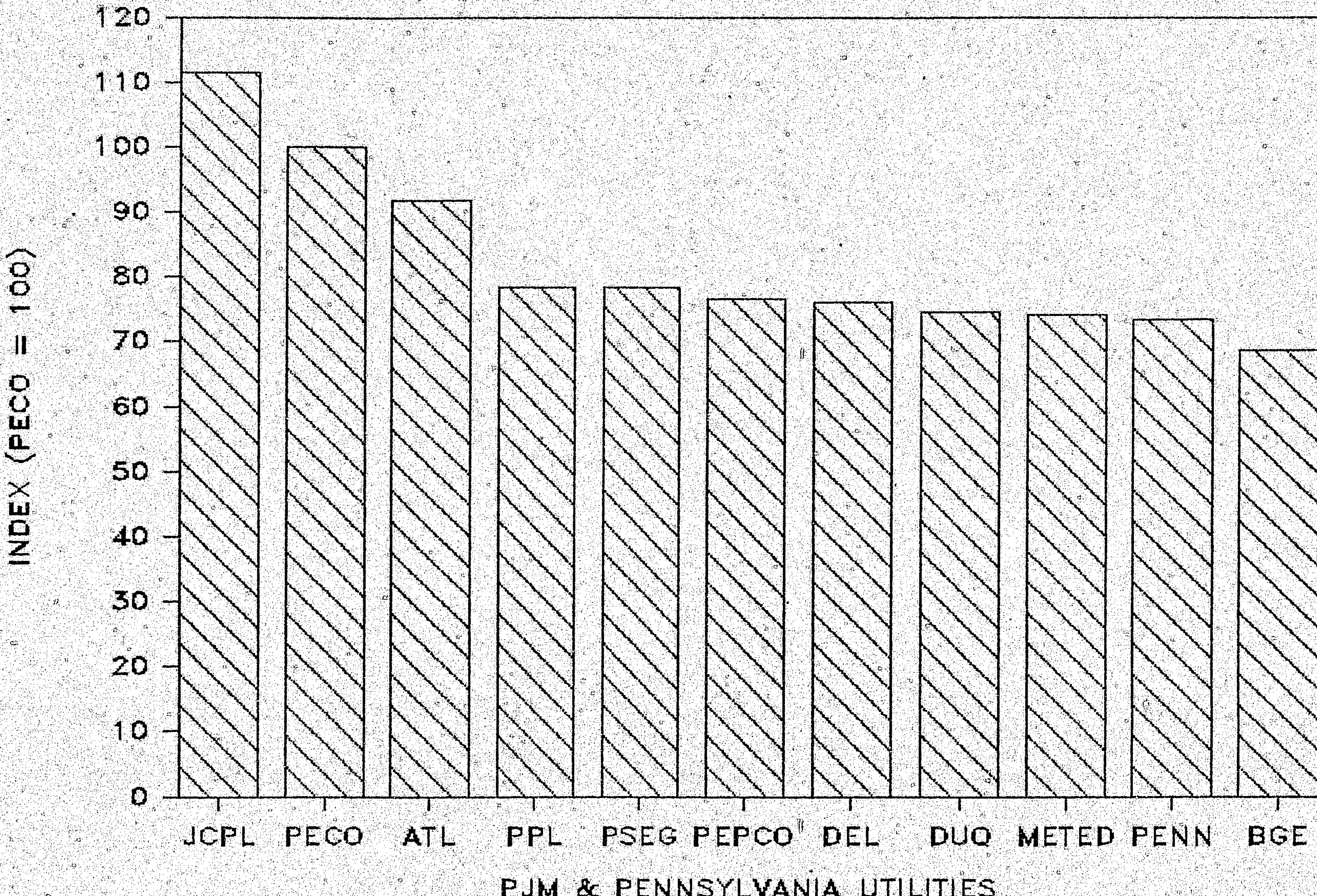
COMPARISON OF PRESENT RATES
For non-manufacturing HT customers
in different utility service territories

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



urce: Utility Rate Schedules

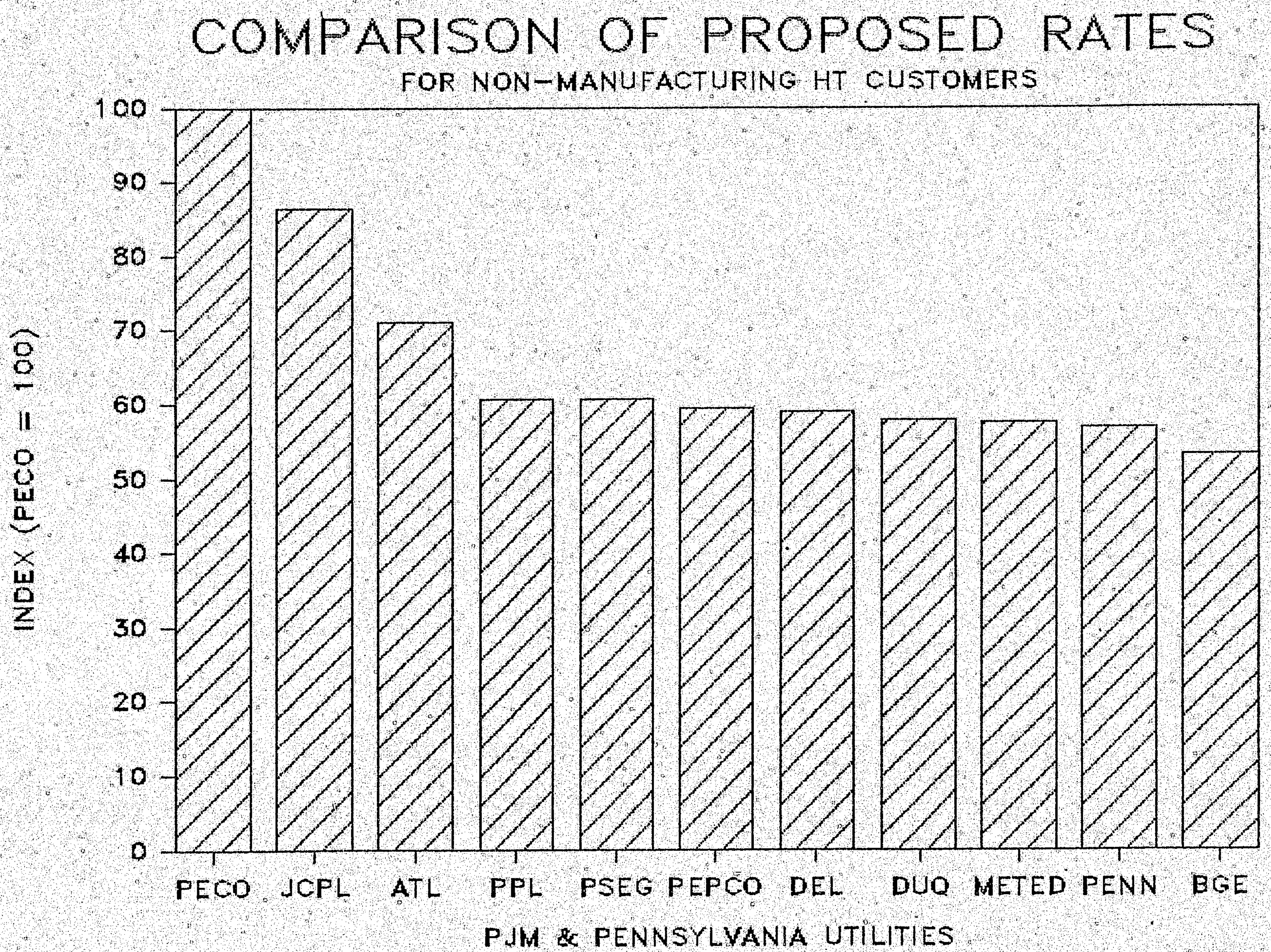
FIGURE SLF 3

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



rce: Utility Rate Schedules

FIGURE SLF_4

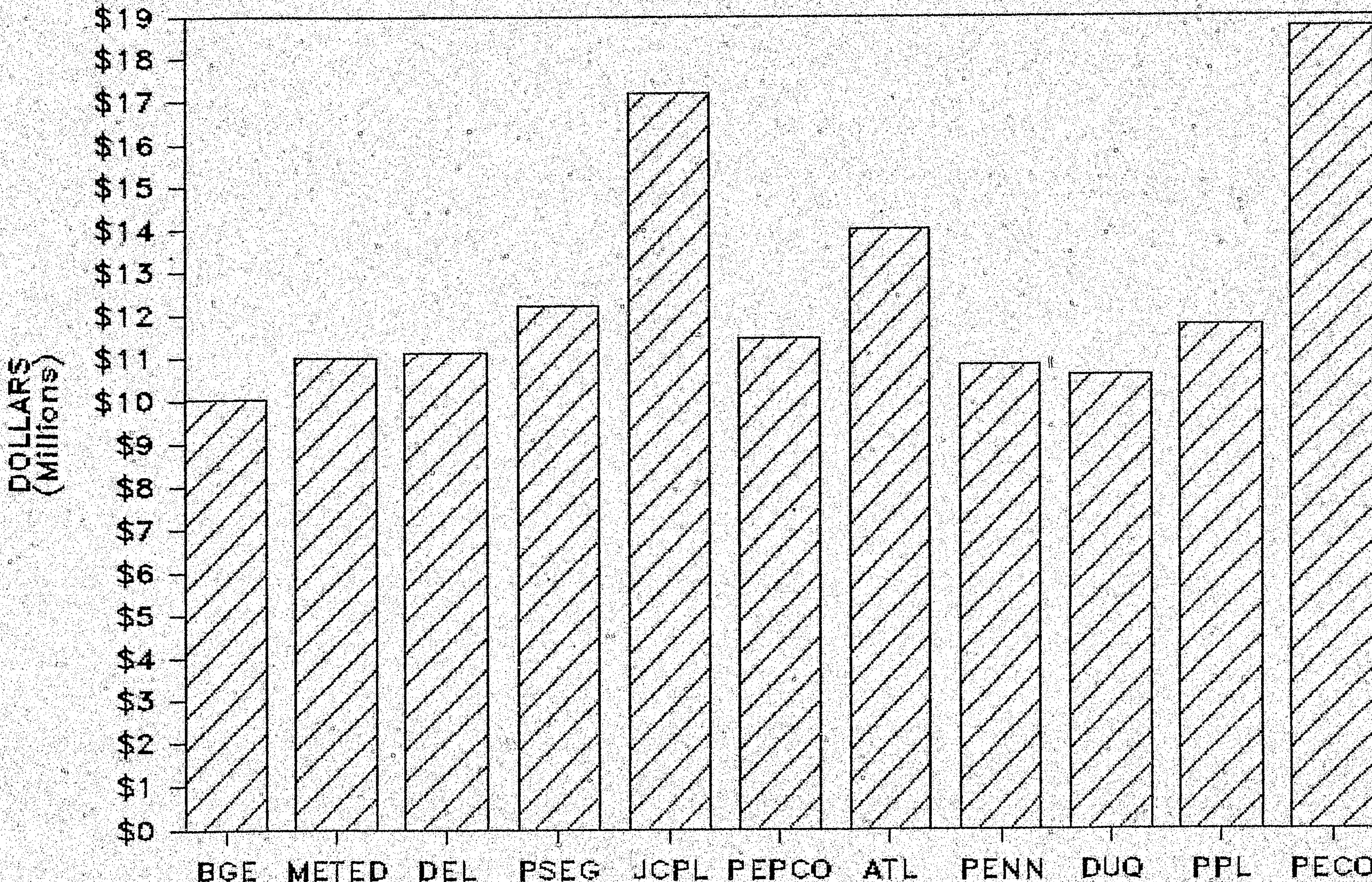
TABLE SLF__5

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

ANNUAL ELECTRICITY BILLS

UNIV. OF PENN.– FOR DIFFERENT UTILITIES



urce: Univ. of PA electric bills
& utility rate schedules.

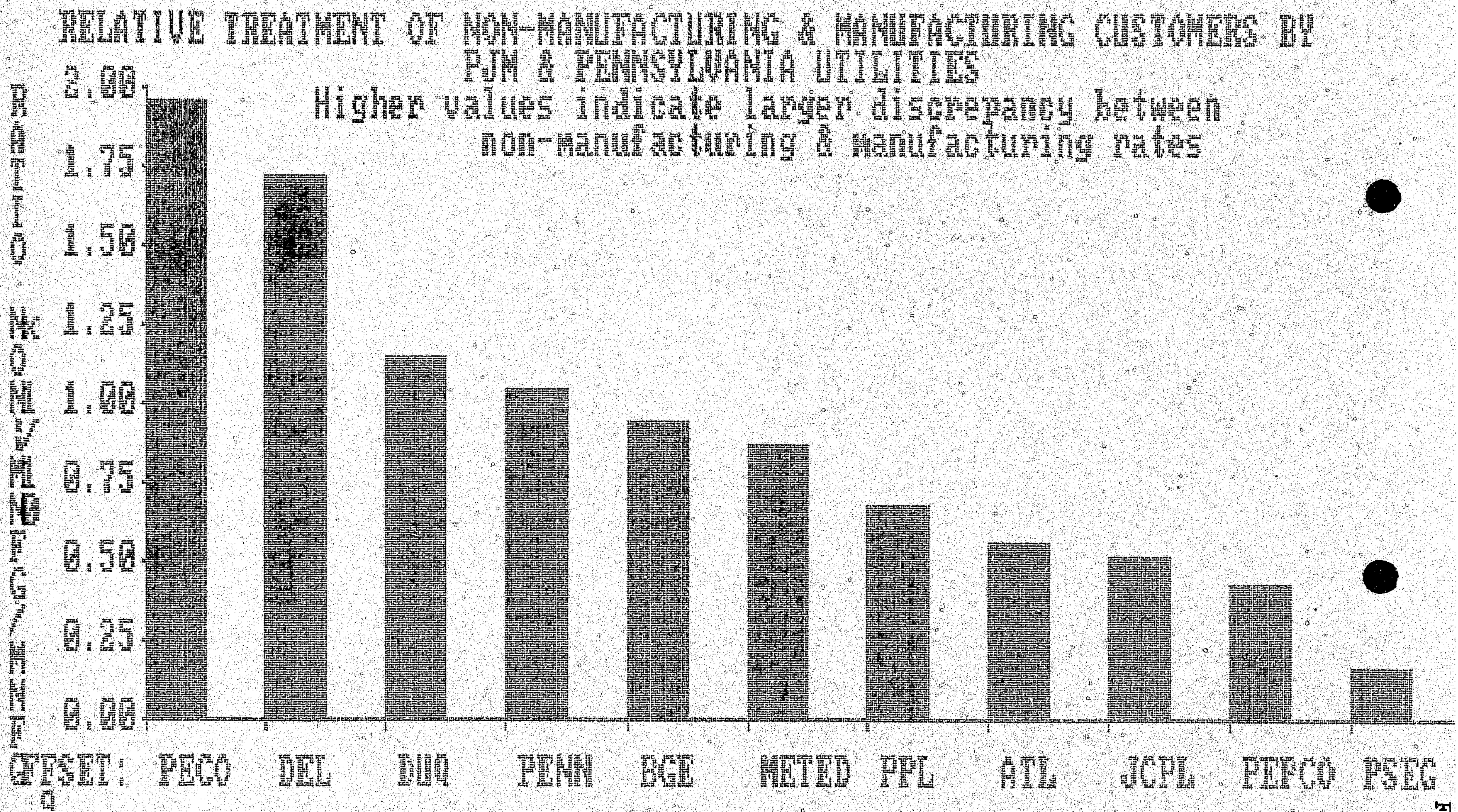
FIGURE SLF 5

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



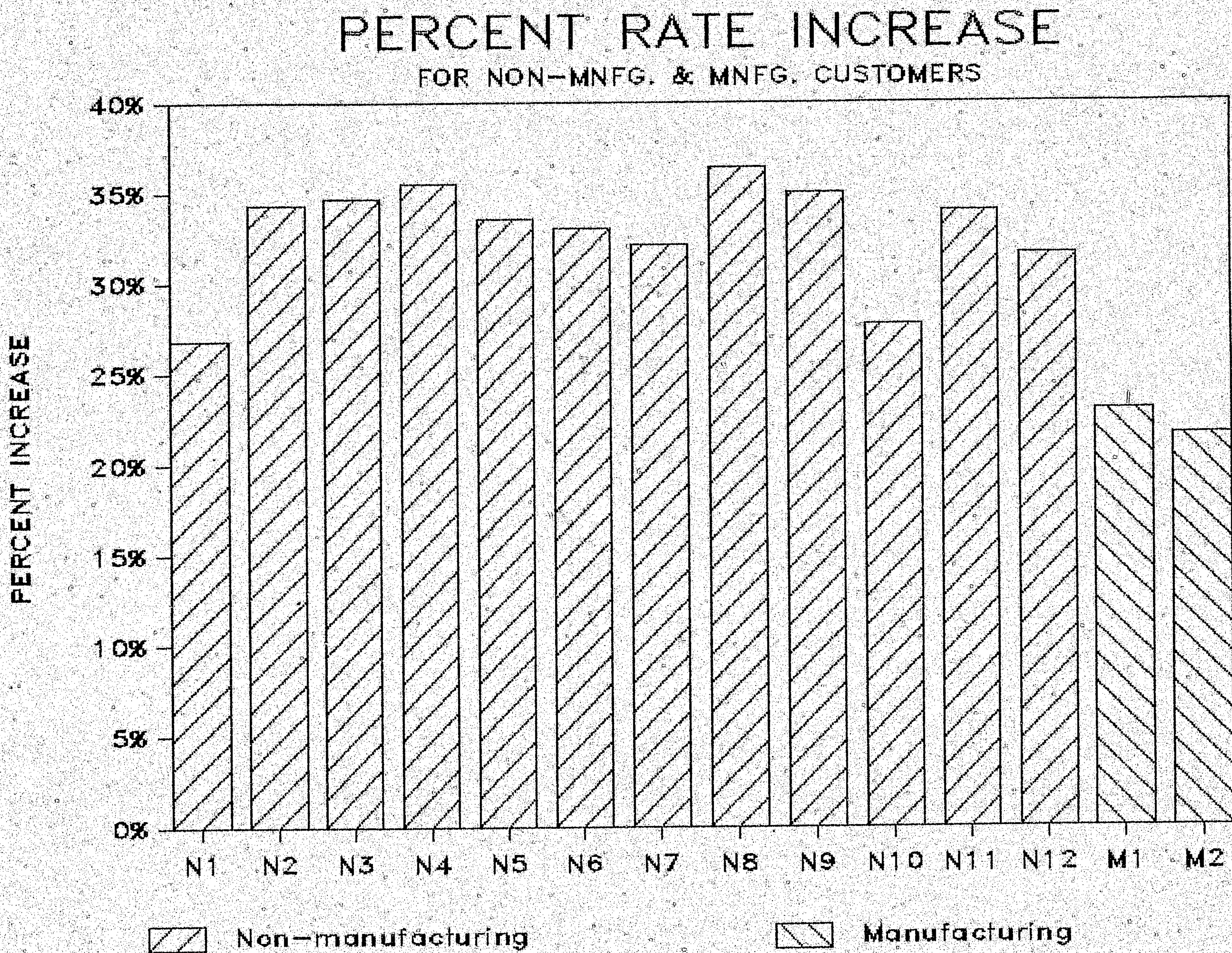
ce: UUC member electric bills & hypothetical Mnfg. bills/Analysis of utility rate schedules.

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%



ource: UUC member electric bills
& hypothetical mnfg. bills/
Analysis of PECo rate
request.

FIGURE SLF 7

ERRATA
FOR THE TESTIMONY OF
S.L. FELDMAN

1. SLF p. 4, line 11: "rate classes" should read "rate class".

2. SLF p. 9, line 12: "...non-manufacturing rates for PECo would be on average 60.7% higher than rates of the other PJM utilities." should read "...non-manufacturing rates for PECo would be on average 60.7% higher than rates of PJM utilities and those Pennsylvania utilities analyzed."

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5. TABLE SLF__1, line 30: "U.S. AVG." should read "SAMPLE AVG.".

6. TABLE SLF__3 should be replaced by Attachment TABLE SLF__3 (Revised).

7. TABLE SLF__4 should be replaced by Attachment TABLE SLF__4 (Revised).

8. TABLE SLF__5 should be replaced by Attachment TABLE SLF__5 (Revised).

9. TABLE SLF__6 should be replaced by Attachment TABLE SLF__6 (Revised).

10. FIGURE SLF__6 should be replaced by Attachment FIGURE SLF__6 (Revised).

Attachment TABLE SLF__3 (Revised)

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present rates

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Attachment TABLE SLF__4 (Revised)

COMPARISON OF PROPOSED RATES
For non-manufacturing HT customers
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	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
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Attachment TABLE SLF__5 (Revised)

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Attachment TABLE SLF__6 (Revised)

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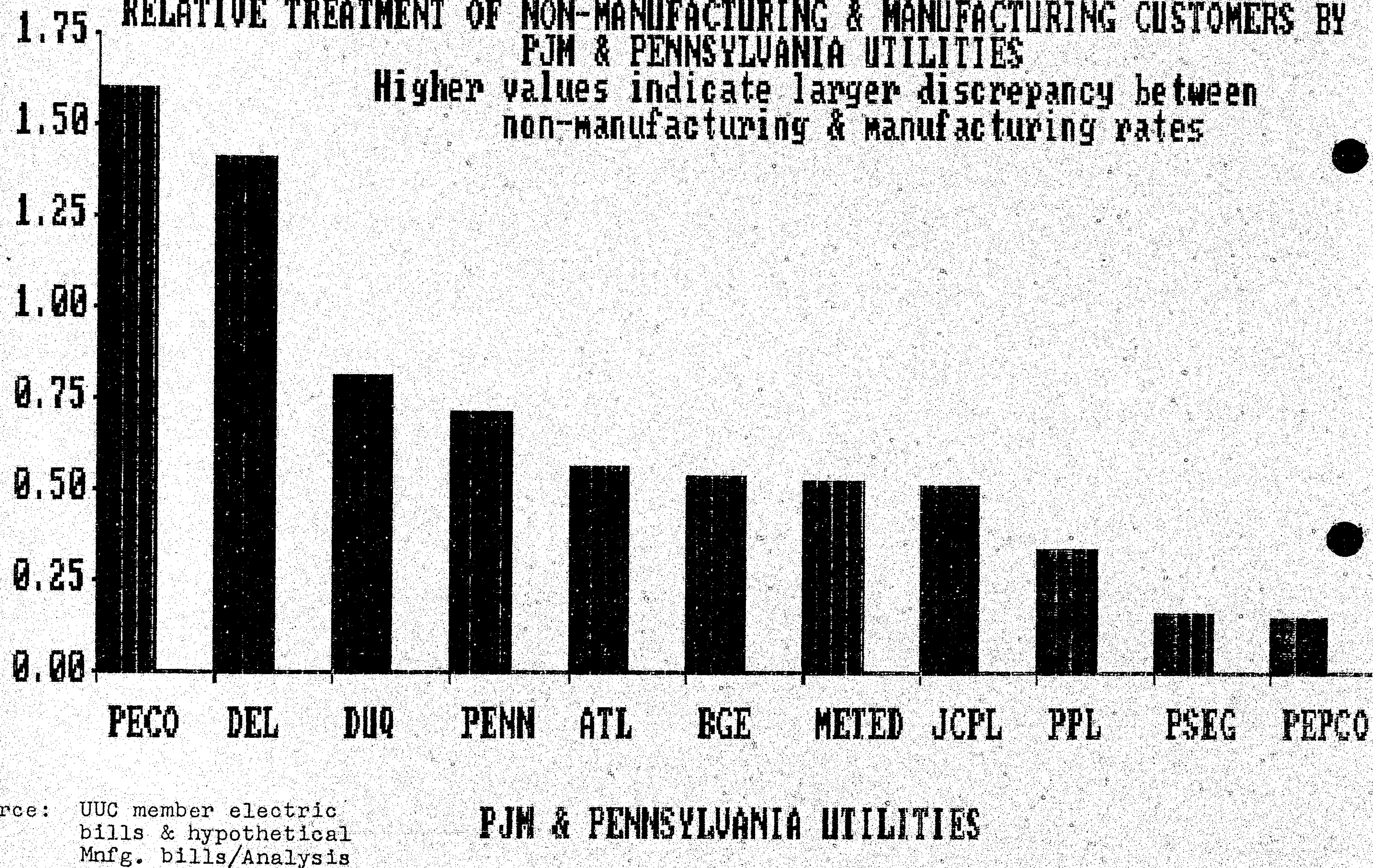
BY PJM & PENNSYLVANIA UTILITIES

Higher values indicate large discrepancy between non-manufacturing & manufacturing rates

UTILITIES	RATIO NON-MANUFACTURING/MANUFACTURING
Philadelphia Electric Co.	1.0603
Delmarva Power & Light	1.0420
Duquesne Light Co.	0.9822
Pennsylvania Electric	0.9716
Atlantic Electric	0.9564
Baltimore Gas & Electric	0.9549
Metropolitan Edison	0.9532
Jersey Central Power & Light	0.9524
Pennsylvania Power & Light	0.9349
Public Service Electric & Gas	0.9163
Potomac Electric Power Co.	0.9158

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.

Attachment FIGURE SLF_6 (Revised

FOR THE TESTIMONY OF
S.L. FELDMAN

FEB 24 1986

SECRETARY'S OFFICE
Public Utility Commission

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For non-manufacturing HT customers
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RELATIVE TREATMENT OF NON-MANUFACTURING & MANUFACTURING CUSTOMERS BY PJM & PENNSYLVANIA UTILITIES

Higher values indicate large discrepancy between non-manufacturing & manufacturing rates

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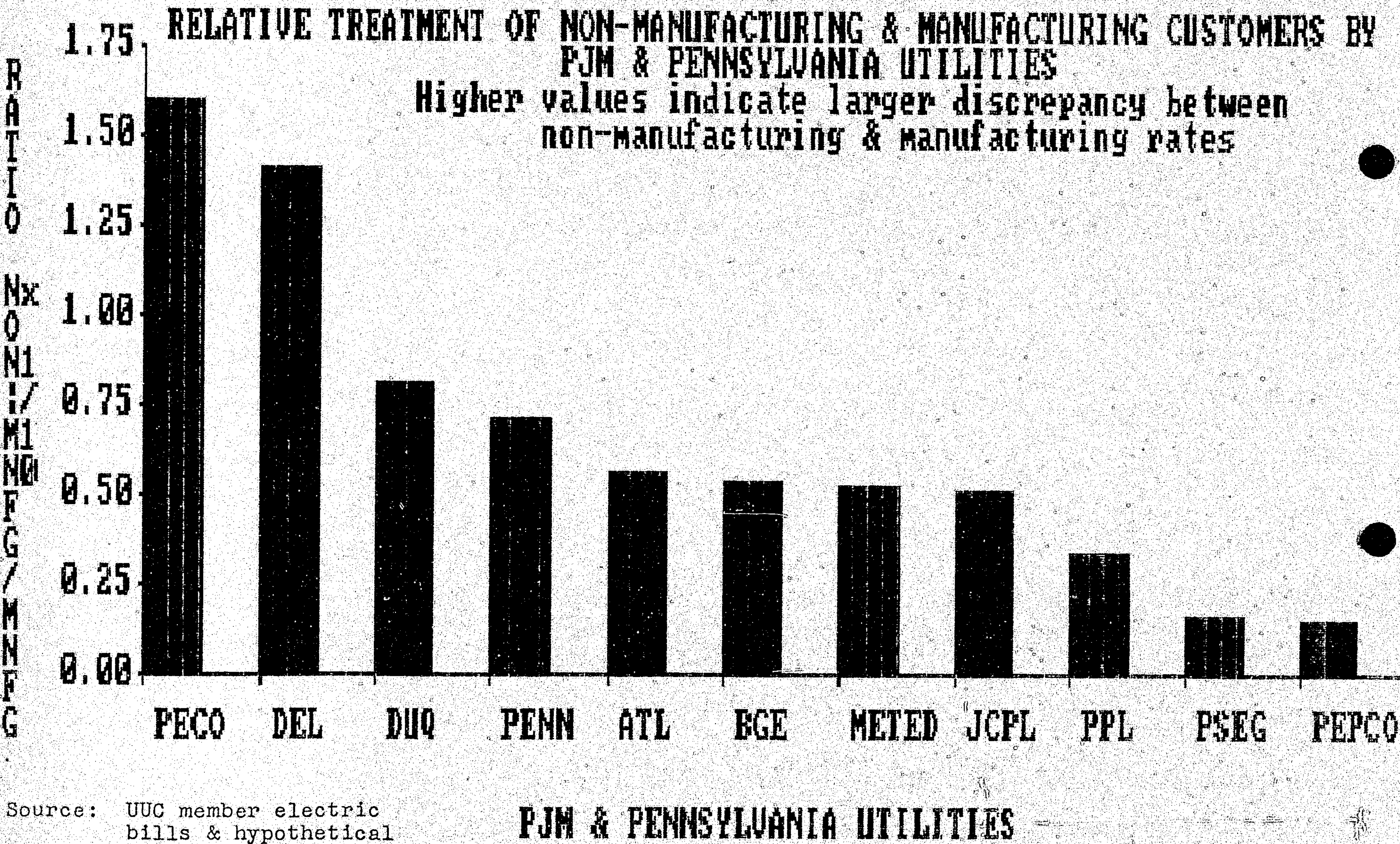


Source: UUC member electric bills & hypothetical Mnfg. bills/Analysis of utility rate schedules.

Attachment FIGURE SLF 6 (Revised

RECEIVED

FEB 24 1986

SECRETARY'S OFFICE
Public Utility Commission

COMMONWEALTH OF PENNSYLVANIA
BEFORE THE PUBLIC UTILITIES COMMISSION

THE PENNSYLVANIA PUBLIC UTILITIES COMMISSION V. PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

UP/UUC STATEMENT #3 2-21-86

TESTIMONY OF DR. ROBERT M WIRTSHAFTER
ON BEHALF OF THE
UTILITY USERS COMMITTEE/
UNIVERSITY OF PENNSYLVANIA

January 22, 1986

DOCKETED
FEB 26 1986

DOCUMENT
FOLDER

TESTIMONY OF ROBERT M WIRTSHAFTER

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD?

A. My name is Robert M Wirtshafter; I am employed by Delphi Energy Group, Inc., Suite 255, 3508 Market St., University City Science Center, Philadelphia, PA 19104.

Q. COULD YOU BRIEFLY DESCRIBE YOUR EXPERIENCE IN THE ENERGY FIELD?

A. I have bachelors and Ph.D. degrees from Clark University where I specialized in the analysis of electric utilities and energy conservation problems and the development of policy models to project the impact of rising energy prices upon consumers, utilities and government. In 1979, I left Clark to pursue employment with the Tennessee Valley Authority. At TVA my responsibilities were in policy planning in the Division of Conservation and Rates as an advisor overseeing more than a dozen projects in energy conservation and rate design. At the beginning of 1981, I joined Delphi Energy Group, Inc. as a principal and vice president. I have been involved in testimony for Delphi's local clients providing service to the Building Owners and Managers Association, the University of Pennsylvania, and the Utility Users Committee. I have testified before this Commission on prior Limerick cases. In addition to my responsibilities at Delphi Energy Group, Inc., I am Research Assistant Professor at the Energy Center of the University of Pennsylvania. I have co-authored one book on public utilities and have published extensively in energy journals such as <u>Energy Policy</u>, <u>Energy Economics</u>, <u>The Journal of Energy</u>, <u>Public Utilities Fortnightly</u>, etc. I teach a post-graduate course in regulatory policy at Penn, as well as several courses in energy conservation and cogeneration.

Q. COULD YOU SUMMARIZE YOUR OBJECTIONS TO THE COMPANY'S PROPOSED COST ALLOCATION AND RATE STRUCTURE?

A. My principal objection is in the way that the Company treats the costs of generation capacity. I will show that the Company allocates all of Limerick's generation costs to the demand component of the tariff structure despite the fact that the construction of the plant is justified by the greater energy (fuel) savings it should offer over the existing capacity. As a result, rate discrimination appears at both the interclass and intraclass level of the HT class. Several rate classes that have low coincidence with the four summer peaks escape paying for their rightful share of the Limerick I costs. The lower load factor customers in the HT rate class are receiving a higher percentage increase than high load factor customers despite the greater benefits that are expected to accrue to the higher load factor customers from Limerick I fuel savings. The manner in which PECo collects those revenues is from demand charges and the associated demand ratchet.

Q. COULD YOU SUMMARIZE THE CONCLUSIONS OF YOUR TESTIMONY?

A. Yes. Lower load factor customers and those with high summer to winter demand ratios in the HT customer class are unfairly discriminated against within their class in favor of higher load factor customers. The former designation in general describes non-manufacturing (commercial, institutional and high-rise residential) customers while the latter is generally descriptive of manufacturers.

There are three components to the discrimination. **First, the demand ratchet is no longer justified since it overcollects revenues and is not an appropriate price signal. Second, the explicit demand charge increases are almost three hundred percent of the overall rate increase. Third the Company has failed to allocate an appropriate part of the rate increase to the tail energy block.**

Continuation of the demand ratchet is unjustified in view of both the Company experience and more particularly the experience of the HT class. This lack of justification occurs because of four primary reasons. First, the ratchet imposes a very large impact upon the average commercial and institutional customer. An increase of one kilowatt of demand during the summer months by a customer adds $24.00 to a non-manufacturing customer's annual bill, but as much as $120 to a non-manufacturing customer's annual bill. Second, the cost of the same kilowatt to PECo is less than $10, or less than ten percent of the revenues it receives from the non-manufacturing customer. Third, the ratchet applies only to the HT and PD customers plus AMTRAK and SEPTA. Other customer classes do not suffer its effects. Therefore, the cost of the additional kilowatt to residential customers is zero. Fourth, the ratchet is used by only two other utilities in the region, and its impact upon PECo customers is four times the impact of the next highest utility.

The proposed demand charge (assuming PECo gets 100% of its rate request) should be lowered from $9.44 /kw to $5.34 /kw and the energy block charges should be adjusted from $0.0964 /kwh to

$0.0948/kwh for the first block, $0.0668 /kwh to $0.0764 /kwh for the second block and $0.0375 /kwh to $0.0591 /kwh for the tail block for the HT class.

These changes are justified since the Company does not allocate the costs of its generation and transmission capacity correctly. The Company allocates its costs on the assumption that Limerick I is entirely needed for capacity, when in fact the plant is needed more for its fuel savings. Allocating the appropriate amount of plant costs to fuel savings results in the reallocation suggested herein.

Q. DR. WIRTSHAFTER, HOW WILL YOU DEMONSTRATE THE ABOVE POINTS?

A. First, I will compare PECo's rate structure to other utilities. Second, I will show that PECo's four peak method to allocate costs must be modified given the proposed addition of Limerick I. Third, I will demonstrate the true effects of the demand ratchet. Fourth, I will reallocate costs to compute a tariff structure that truly tracks the Company's additional costs as a result of Limerick I.

I. Comparison of Customer Bills Between Utilities

Q. DID YOU PERFORM ANY ANALYSIS OF THE RATE STRUCTURES OF OTHER ELECTRIC UTILITIES IN THE AREA?

A. Yes. In addition to PECO, the analysis was performed on Pennsylvania Power & Light, Pennsylvania Electric, Metropolitan Edison, Duquesne Light Co., Delmarva Power & Light, Potomac Electric Power Co., Baltimore Gas & Electric, Public Service Electric & Gas, Jersey Central Power & Light, Atlantic Electric Co., and Consolidated Edison.

Q. WHAT TYPE OF ANALYSIS DID YOU PERFORM TO DETERMINE THE

RELATIVE RATES LARGE NON-MANUFACTURING CUSTOMERS WOULD FACE IN THE SERVICE TERRITORIES OF OTHER UTILITIES?

A. The HT rate structure of PECO and the equivalent rate structures for other PJM and Pennsylvania utilities were input into a computer spreadsheet. The electrical use patterns of a number of Utility User Committee (UUC) customers were input to each spreadsheet in order to determine what the total electric bill would be if the customers were located in the service territories of the other utilities.

Q. HOW DID YOU TO APPLY INFORMATION FROM PECO ELECTRICITY BILLS TO THE RATE STRUCTURE OF THESE OTHER UTILITIES?

A. In most cases the PECO bill contained all the necessary data. However, in a few cases the on- and off-peak periods for the other utilities covered different hours of the day than those covered by PECO. Therefore, it was necessary to make some assumptions concerning how to convert from PECO's time-of-day schedule to those of the other utilities. We did this by adjusting proportionally by the number of on and off-peak hours within a week.

For simplicity the power factor was set equal to 95% for large load customers and equal to 90% for lower load customers. This involved adjusting PECO's billing demand such that it was equal to registered demand when the ratchet was not in effect.

In addition, the time interval over which demand is registered varies slightly between utilities. It was assumed that demands were unaffected by this interval.

Q. WHAT DID YOU USE FOR THE ENERGY COST RATE?

A. The Energy Cost Rate effective on December 1, 1985 was used for each utility.

Q. HOW WAS THE SAMPLE OF CUSTOMERS SELECTED FOR THE ANALYSIS?

A. The sample of customers was selected based on which UUC customers had supplied us with bills quickly enough for us to include an analysis of them in our testimony.

Q. DID YOU HAVE COMPLETE BILLS FOR ALL THE CUSTOMERS YOU ANALYZED?

A. No. Some customers did not supply us with complete information.

Q. WHAT DID YOU DO WHEN YOU DID NOT HAVE COMPLETE INFORMATION?

A. Very few bills were missing. The few customers which had incomplete bills had a gap of only one month. In these cases the meter readings from the prior and succeeding months were utilized to determine the total kwh used. The demand was calculated as an average of the surrounding months.

Some customers did not supply us with a cycle of bills starting in January and ending in December. For example, the University had their bills from July of one year to the June of the next year. In these cases we used the previous year's peak to set the ratchet just as was done on the bills.

Q. HOW DID YOU ESTIMATE THE USE PATTERNS FOR YOUR SAMPLE NON-MANUFACTURING CUSTOMERS?

A. Two hypothetical manufacturing customer loads were created for our analysis. These were based on the electric load patterns of typical manufacturing users. No variations in billed demand occurred due to seasonal effects, or in other words, the demand ratchet never comes into play. Kilowatt-hour use was split between on- and off-peak use with a 1:2 ratio. Manufacturing customer #1 (M1) had 5000 kw demand and 648 hours usage.

Manufacturing customer #2 had 40000 kw demand and 710 hours usage.

Q. WHAT WERE THE RESULTS OF THE INTER-UTILITY COMPARISONS?

A. Dr. Feldman's testimony deals with the results of the comparisons in a more in-depth fashion than does mine. However, I would like to point out that the analysis show that PECo's large non-manufacturing customers would now pay, on average, thirty percent more than they would if they were located in other utilities. If the proposed rate increase goes into effect these customers' bills will be more than sixty percent higher on average than they would be if they were located in the other utilities' service territories.

II. The Inappropriateness of PECo'S Cost of Service Allocation Methodology

Q. WHAT ARE THE MAJOR REASONS FOR THE HIGH NON-MANUFACTURING RATES IN PECO'S SERVICE TERRITORY?

A. I believe that the reasons are twofold. First, PECo's overall costs even without Limerick are higher than all but one area utility. Limerick costs boost those rates above all area utilities. Second, PECo's rates do not track the allocation of those costs.

Q. THE COMPANY USES THE FOUR PEAK METHOD TO ALLOCATE COSTS. IS THIS JUSTIFIED?

A. Absolutely not. The four peak method of cost allocation is no longer appropriate since it does not represent the basis of PECo costs in 1986. Mr. Sundermeir has stated that, "Production and transmission plant must be designed to meet the maximum demand requirements imposed on the system by customers; therefore, it is appropriate that these costs should be allocated on the basis of contribution to those peak demands." (PECo statement #24, p.6, lines 19-23). While there is nothing incorrect about the first half of Mr. Sundermeir's statement (that production and transmission plant must be designed to meet the maximum demand requirements imposed on the system by customers), it is certainly incomplete. As Mr. Rush confirms production and transmission plant must be designed not only to meet maximum demand requirements, but also to provide electricity at the lowest overall cost to customers (PECo Statement #14, page 17, lines 19-33.). Mr. Sundermeir would like us to believe that all of the production and transmission costs are incurred for reliability purposes. The facts in this case are that most of the costs of the Limerick I plant are being added for energy savings rather than meeting peak demand and that those costs of Limerick I are more properly added to the energy category. With the inclusion of Limerick I, the four peak method is completely unsupportable.

Q. WHAT EVIDENCE IS THERE THAT LIMERICK I IS NOT BEING ADDED TO EXCLUSIVELY MEET PEAK REQUIREMENTS?

A. Prior to the cancellation of the combustion turbines, the Company already had sufficient capacity without including Limerick I. Concurrently with the addition of Limerick I into the Company's rate base, the Company is cancelling an almost equivalent amount of existing capacity. This is well-documented in the testimony of Mr. Paul Chernick on behalf of the Utility Users Committee in this Docket. PECo's own witness, Mr. Rush, the witness responsible for providing the justification for Limerick I, admits that a major portion of the plant is not being built for reliability purposes. (TR 822, lines 8-11.) His justification of Limerick centers on the expected fuel savings and on the need to replace existing peaking capacity with baseload capacity (PECo Statement #14, page 20, lines 29-35).

Q. WILL A DIFFERENT COST ALLOCATION METHOD PRODUCE A DIFFERENT RESULT?

A. Yes. The Company has provided the calculations for only one other cost allocation methodology, the average and excess allocation method. The results of that methodology produce very different results. Schedule RMW__1 shows the differences between the class rates of return for the different classes under each of the two allocation methods. Under the average and excess method the RH, OP, Street Lighting, EPS and EPA rates exhibit class rates of return well below system average. The difference in the two cost methods, shown in Column 3 of RMW__1 illustrates the complete reversal in class rates of return that are realized by the RH, OP, Street Lighting, EPS and EPA rates. Under the average and excess method, the deviations from system average rate of return are exacerbated by the proposed rate increase. These deviations are shown in RMW__2 and RMW__3. Under the average and excess method, the rate classes that are significantly below system average rate of return are the very rate classes that PECo has singled out for special treatment. Column 4 of RMW__2 shows the relative increases of each class of customers as proposed by the Company. While the rate increases for the HT, PD, GS, and R customer classes are increased by 29.6 percent, the RH, OP, Street Lighting, EPS, and EPA customer classes are given smaller percentage increases.

Q. WHY DO THE RESULTS DIFFER SO MUCH BETWEEN THE TWO ALLOCATION METHODS, AND HOW SHOULD THE COMMISSION INTERPRET THESE RESULTS?

A. The four coincident peak method assigns all of the costs of Limerick based on contribution to system peak. The average and excess method recognizes that costs to PECo are both energy and demand related. In the average and excess case, a portion of the costs of capacity are assigned based on energy, and the remainder is allocated based on non-coincident peak demand. The four peak method allocates only a small portion of the cost burden of Limerick to classes with a low system peak coincidence factor. Since Limerick is a baseload plant that is in major part replacing existing peaking capacity, these classes will share in the benefits of lower fuel costs. The Commission should recognize that these rate classes must share in the cost of the Limerick plant. It should be emphasized that the present PECo request gives the greatest rate relief to the very classes that under the average and excess method should bear the greatest increases in rates.

Q. ARE YOU ADVOCATING ADOPTION OF THE AVERAGE AND EXCESS METHODOLOGY?

A. No, I am not. I offer the above example to illustrate how sensitive the class rates of return are to different allocation strategies. In this case, the issue is not so much whether one cost allocation method is superior to the next, but whether portions of the production and transmission expenses are more properly classified as energy related under any methodoology. The average and excess method recognizes that energy savings is a major factor in determining PECo capacity related expenditures.

Based on the findings of the average and excess method, it is clear that the lower percentage rate increases proposed by PECo and given to some rate classes are inappropriate. The Company presents the four peak method as though it perfectly represents the basis of all incurred costs. Yet a major portion of new costs (that incurred by the construction of Limerick) is unrelated to peak capacity requirements. Given the sensitivity of certain classes' rates of return to different allocation methodologies, the partial validity of arguments for each of the divergent allocation methodologies, and the magnitude of the present rate request, complete adherence to the four peak method as defined by the Company is imprudent. I believe that the Commission should recognize that the four coincident peak method cannot be relied upon to accurately allocate PECo's costs. For this rate request, the Commission should raise the rates on an equal percentage basis to all classes of customers.

III. Changes in the HT Rate Structure.

Q. FOR THE HT CLASS, HOW HAS PECO ALLOCATED THE COSTS OF GENERATION?

A. In designing the intraclass rate structure PECo has assigned all capacity costs to the demand component.

Q. WHAT IS THE ULTIMATE EFFECT OF ASSIGNING ALL OF LIMERICK I COSTS ON A DEMAND BASIS?

A. The impact within the HT class under both of the allocation methods (as interpreted by PECo, which assigns the energy portion of the average and excess costs to the demand component--see IR-UUC/UP 6-1) is that the customers with low load factors are being asked to shoulder a disproportionate share of the costs of

Limerick I. RMW__4, which is a graphic depiction of PECo attachment IV-D-2, for the 1300 kW HT customer, shows the extent of the disparity of the rate increase among different customers of the HT rate class due to load factor.

For the HT customers there is the additional charge of a demand ratchet which further penalizes those customers with high summer peak loads. This demand ratchet is both unfair and obsolete. The combined result is that PECo has the highest demand related charges of any utility in PJM. PECo's proposed demand charges are so out of line that they will be 426 percent higher than Delmarva Power and Light, the next highest in the area.

Q. YOU HAVE STATED THAT YOU BELIEVE THE RATCHET IS OBSOLETE AND UNFAIR. COULD YOU PLEASE EXPLAIN WHAT THE RATCHET IS AND HOW IT WORKS?

A. The ratchet is only applied to the HT, PD, and EP rate classes. The ratchet penalizes customers with high summer demands by artificially setting a demand level of eighty percent of the highest summer demand as the minimum winter billed demand. This ratchet forces many customers to pay demand charges in the eight non-summer months above actual use. This subsequently forces customers into the higher energy blocks causing additional penalties.

Q. COULD YOU GIVE AN EXAMPLE AS TO HOW THE DEMAND RATCHET WORKS?

A. Suppose that a customer uses 1875 kW of demand in August and 1000 kW in each of the following eleven months. Also assume that monthly use is 500,000 kWh in each month of the year. The ratchet imposed on this customer in the non-summer months will be eighty percent of his highest demand in the preceeding summer, in this case 80% of 1875 kW. A demand ratchet of 1500 kW will be imposed on this customer because of his winter demands. The customer will be billed for 1500 kW of demand instead of his actual demand of 1000 kW. Furthermore, because the energy blocks are determined by billed demand and not actual demand, more energy (75,000 kWh) is charged in each of the first two energy blocks as a direct result of the demand ratchet. RMW__5 shows a breakdown of this hypothetical customer's bills for one winter month with and without the ratchet. For this customer, the ratchet costs for this month are $11,335 or 22% more than if no ratchet were imposed.

Q. WHAT IS THE EXTENT OF THE COSTS OF THE RATCHET TO LOW AND MEDIUM LOAD FACTOR CUSTOMERS?

A. I have done the analysis for the sample of UUC members. The results are shown in RMW__6 and RMW__7. Under the proposed rates for the University of Pennsylvania (UUC Customer #1), the ratchet increases the annual bill by $650,000. This represents an addition of 3.4 percent over the charge that would be applied if there was no ratchet. For the other ten UUC members, the ratchet penalty varies from 0.8% to 5.7%. On average these members' bills are increased 3.2% percent by the inclusion of the ratchet.

Q. WHAT IS THE IMPACT OF THE RATCHET ON THE ENTIRE HT CLASS?

A. Despite PECo's insistence that the demand ratchet is a good idea, and the UUC's constant challenge to its validity, the Company cannot provide a value as to the revenue collected by the ratchet (IR-UUC/UP-4-2, Tr. 1596). I have estimated that PECo will collect $14,442,000 in revenue from the ratchet in the test year under the proposed rates.

Q. COULD YOU EXPLAIN HOW YOU DERIVED YOUR FIGURE FOR REVENUE COLLECTED BY THE RATCHET WITHIN THE HT CLASS?

A. The three tables in RMW__8, RMW__9, RMW__10 show the process by which the ratchet revenue has been calculated. There are three steps to the process. I first calculated the number of extra kilowatts that were collected by the ratchet for 1984. Second, I adjusted this figure to conform to the test year. Third, I estimated the shifts in kilowatt-hours between the rate blocks that result from the ratchet.

RMW__8 calculates the number of kilowatts in the non-summer months that are attributable to the demand ratchet. IR-UUC/UP-4-1 gives the actual and billed demands for the HT class. I used 1984 because it contains the last complete year of data. The billed demands account for the power factor adjustment, the demand ratchet and minimum billing demand. It is assumed that billing demand adjustments are neglible. To the extent adjustments for minimum billing demand are imposed during the summer, my estimate of revenues collected from the demand ratchet is overstated. Therefore, the difference in the billed and actual demand in the summer months is largely a function of the power factor adjustment. Column 4 of RMW__8 shows the average power factor adjustment for the summer of 1.038%. I have adjusted the non-summer billed demands by assuming that they also have similar power factor adjustments as the summer months. Column 5 is the billed non-summer demand without power factor, and the difference between Columns 2 and 5 is the billed demand due to the ratchet as shown in Column 6.

RMW__9 adjusts the figure developed in RMW__8 by adjusting for the change in the number of total kilowatts between 1984 and the test year. This raises the figure slightly from 815,295 to 816,557 kW.

RMW__10 calculates the revenues that would be lost from removing the ratchet. In the first case it is assumed that every ratcheted customer has over 300 hours use. In this extreme case every kilowatt of billed demand due to the ratchet will also shift 150 kwh into each of the first 2 blocks from the third block. This case (line 4) measures the maximum amount of revenue that would be collected by the ratchet. For the HT class this figure is $14,922,572.

Lines 5 through 8 calculate the actual block changes for our sample of twelve UUC members, all of whom are affected by the ratchet. Several of these customers have loads that are less than 300 hours of use. For these customers the ratchet does not shift as much energy from the third block to the second block. (there is no more energy in the third block). The impact is shown in line 7, where 5,250,000 is less than 150 hours multiplied by 40,406. Having established the impact on the known group of HT customers, I extrapolate a value for the entire HT class based on the ratio of sample billed kilowatts due to ratchet over total billed kilowatts due to ratchet. This adjustment lowers the estimate of the revenue collected by the ratchet by about three percent to $14,442,424.

Q. ACCORDING TO THE COMPANY WHAT IS THE PURPOSE OF THE RATCHET?

A. Mr. Sundermeir has given the following reasons for the ratchet in the Case R-8222912, Statement 3A, July 1983.. He states: "The purpose of the demand ratchet is to send a price signal to HT customers encouraging them to reduce their summer demand. These demand reductions benefit all customers through lower fuel costs and in decreasing the need to add new capacity. Moreover, the ratchet also ensures that the Company will at least partially recover the costs it incurs to supply an additional kW of demand during the summer." Under cross examination in this case (TR 1595-96), Mr. Sundermeir reconfirmed this statement, and stated that there were no other reasons for the ratchet (TR 1596).

Q. WHAT IS WRONG WITH THE JUSTIFICATION OF THE RATCHET GIVEN BY MR. SUNDERMEIR?

A. The justification for the ratchet, as given by the Company, has not changed in many years. However, the costs and capacity conditions of the Company have been consistently changing. Since the construction of Limerick I, the claims for the ratchet have even less validity when examined against the actual situation which the Company is now in. I will demonstrate this below. Finally, the ratchet is unfair in that it is regularly imposed on only the non-manufacturing sub-class of customers.

Q. MR SUNDERMEIR STATES THAT THE RATCHET IS A SIGNAL USED TO ALERT HT CUSTOMERS OF HIGH SUMMER USAGE. WHAT EVIDENCE DO YOU HAVE THAT THE RATCHET IS UNFAIRLY IMPOSED?

A. Mr. Sundermeir's own statement strongly demonstrates the unfairness. He justifies imposing the ratchet on HT customers because demand reductions will benefit <u>all</u> customers through lower fuel costs and in decreasing the need to add new capacity. This is blatant discrimination, for HT low and medium load factor customers are asked to make sacrifices or pay penalties for the benefit of other customer classes.

Q. MR. SUNDERMEIR HAS STATED THAT THE RATCHET IS THE SIGNAL THAT PECO USES TO ALERT HT CUSTOMERS AS TO THE UNDESIRABILITY OF ADDING TO THE SUMMER PEAK LOAD. IS THIS THE SAME SIGNAL GIVEN TO OTHER CUSTOMERS?

A. No. The signal given to the HT low and medium load factor customers is drastically out of line with the signal given other classes of customers. I have examined the bills of the University of Pennsylvania and compared them to hypothetical bills from other PECo customer classes to determine exactly how strong a signal the ratchet is. For each class, I have measured the additional rate charges that result from the addition of one kilowatt demand during the highest summer month.

If this greater demand does impose greater costs to PECo, an assertion that I will challenge below, it must be accepted that the addition of one kilowatt of demand imposes the same costs to PECo regardless of which customer class demands the additional kilowatt. Yet, the ratchet's effect is felt only by the non-manufacturing class. RMW__11 and RMW__12 shows the discrepancy in the charges. The R and RH customers are assessed no charge for the additional demand. The manufacturing customer receives a signal of $24.00. The University of Pennsylvania's signal is $120, or $120 larger than the R and RH customer's signal and $96 larger than the signal to the industrial customer.

Q. IS THE RATCHET SIGNAL FOR HIGH SUMMER TO WINTER USERS DIFFERENT FOR OTHER REGIONAL UTILITIES?

A. I tested the impact of this proposed rate treatment against that of other PJM utilities and Con Ed. For each utility, I added ten more kilowatts to the summer peak month demand of the University of Pennsylvania bill. (Ten kilowatts was used so that fractional kilowatts of ratcheted demand would be avoided.) I then recalculated the annual bill under each utility's appropriate rate. The results are revealed in RMW__13 and RMW__14. PECo's charge for the additional ten kilowatts is by far the highest of any utility. In fact, as graphically shown in RMW__9, the charge is over four times that of the next highest utility. Even without the ratchet, PECo's charge would be the second highest.

Q. MR. SUNDERMEIR HAS STATED THAT THE RATCHET IS NECESSARY TO ENSURE THAT THE COMPANY WILL AT LEAST PARTIALLY RECOVER THE COSTS IT INCURS TO SUPPLY AN ADDITIONAL KW OF DEMAND DURING THE SUMMER. WHAT IS WRONG WITH THIS ARGUMENT?

A. The claim that the ratchet is necessary to collect sufficient revenue from customers may at one time have been valid. The simple fact is that it does not cost PECo $120 per year to meet this type of capacity addition.

The Company's own witness, Mr. Rush, states that for economical purposes loads that occur for brief periods should be met by peaking units characterized by low capital costs (PECo Statement #14, page 18 line 30 to page 19 line 14). If the Company needed to buy new peaking capacity, it could do so by adding new peaking capacity at $52.93 per kw/year (the cost established by PJM as the cost of new peaking capacity, see IR-OCA-9-12).

The fact of the matter is that additions to peak demand would not impose large additional charges to the Company. The cost of maintaining the 458 MW of leased combustion turbines is approximately $5,000,000 or $10.00 per kW/year. Even without the ratchet, the demand related charges (implicit and explicit) overcollect the costs of buying new peaking capacity. The imposition of the ratchet means that the Company overcollects from the ratcheted customers by an order of 10 times the proper charge for additional summer demand.

In addition, the Company has provided testimony concerning the present difficulties it experiences in trying to schedule maintenance of its baseload facilities. Mr. Rush noted in cross examination that the Company attempts to schedule baseload in the "valley period of loads." (see TR-342-345). He indicates that it is not always possible to schedule all baseload in the spring and fall. Under these conditions, the Company is forced to schedule some baseload maintenance first in the winter and if necessary in the summer. The ratchet actually encourages some customers to have higher demands in the winter than they otherwise would with no ratchet. This reduces PECo's ability to schedule demand through the winter, and forces a greater need for scheduled maintenance during the summer.

Q. ARE YOU ASKING FOR AN ELIMINATION OF THE RATCHET?

A. Yes. It should be pointed out that the demand ratchet is not generally used by other utilities. Of the eleven other utilities that I examined, only two, Metropolitan Edison and Delmarva have demand ratchets. In both cases the impact of the ratchets is significantly smaller than PECo's proposed demand ratchet. Met Ed has a ratchet that is set to only fifty percent of peak summer usage. Delmarva has a higher ratchet, but both lower total demand charges and a lower demand charge in the winter, so the impact of the ratchet is only 23% of PECo's charge.

For PECo, two salient recommendations can be put forth: the ratchet should be eliminated and the demand charge **must be** radically lowered. Only if the demand charge (both explicit and implicit) were lowered to reflect the extremely low costs of providing peaking capacity would the demand ratchet be appropriate according to Mr. Sundermeir's definition.

Q. ARE YOU ASKING FOR FURTHER REDUCTIONS IN DEMAND RELATED CHARGES BEYOND THE RATCHET?

A. Yes, even with the elimination of the ratchet, PECo's demand charge is exceeded only by one utility. Our estimation of the impact of the ratchet is that it only accounts for 1.3% of the total revenues of the HT class, but it falls squarely upon the non-manufacturing customer. Even with the removal of the ratchet, the non-manufacturing HT customers will still receive rate increases significantly higher than our illustrative hypothetical manufacturers. RMW__15 shows the percent increases that will result if the ratchet is removed and the revenue is collected from all other customer classes.

IV. The Appropriate Reallocation of Rates

Q. HOW WOULD YOU REALLOCATE RATES WITHIN THE HT CLASS?

A. The process is rather straight-forward. I have reallocated Limerick I revenue requirements from the demand component to the energy component. I have also redistributed the revenues from the elimination of the demand ratchet to the energy component. I followed PECo's methodology for deriving rates within the HT class using the Bary curve to track cost components to actual rates within the HT class. RMW__16 shows the reallocation that results from this procedure. In this particular case I assume that one hundred percent of Limerick I plus common facilities costs are included in the rate base. Line 1 indicates the total revenue requirements for Limerick I and common of $858,170,000. I have used the A1 allocator (line 2) to determine the portion of Limerick revenues which would be derived from the HT class ($355,814,000 line 3). Line 4 shows the total annual revenue requirement for the HT class as calculated by PECo. Line 5 indicates my Limerick adjustment between the four peak and energy components. I have shifted 90 percent of Limerick costs, $320,233,000, from demand to energy. Ten percent of Limerick costs assignable to the HT class, or $35,581,100, remain in the demand component. Line 6 shows the new annual revenue requirements. Lines 7 and 8 use the same procedure to redistribute demand ratchet revenues from the four peak to the energy component. Line 10 adjusts the Company cost function divisors to the appropriate function divisors without the inclusion of ratchet demand. Line 12 follows the Company procedure to calculate the Total Unit Annual Costs to Serve. The results show that the demand component is lowered from $335.18 to $200.40 and the energy component is raised from $.02603 to $0.05188.

Q. WHAT RATES RESULT FROM THE COST OF SERVICE CALCULATIONS?

A. On a spreadsheet, I have replicated in RMW__17, RMW__18, and RMW__19 the rate setting procedure used by PECo as presented in IR-PAIEUG-1-50. The resulting rates for the energy blocks are $0.0948, $0.0764, $0.0591. The demand charge is $5.34 and is set to ensure that the Company recovers the equivalent amount of revenue as under their proposed rates.

Q. WHAT IS THE RATE INCREASE FOR THE VARIOUS HT CUSTOMERS?

A. The rate increase would fall most heavily on the high load factor customers (RMW__20). However, this is the result of treating Limerick as a facility that is primarily designed to save energy costs. This is the proper direction for the rate increase because these customers stand to gain most of the projected fuel savings. If the Commission does not believe that the fuel savings are adequate to justify placing such a heavy burden on the energy portion of the rate, then the justification for Limerick's inclusion into the rate base at all is null.

Q. DR. WIRTSHAFTER, WHAT WILL YOUR RATES BE IF THE COMMISSION ONLY ALLOWS A PORTION OF LIMERICK INTO THE RATE BASE?

A. If the Commission lowers the request made by PECo than this reduction should be reflected in the energy component. Under these circumstances, I propose that no change be made in the absolute dollars assigned to the demand component. That is I suggest that the demand component be assigned $35,814,000 regardless of the total amount assigned to the HT class. As an example, I have calculated another set of rates assuming that the Commission only allows 50 percent of Limerick into the rate base. The results are shown in RMW__21 through RMW__25.

Q. DR. WIRTSHAFTER, COULD YOU EXPLAIN YOUR REASONING BEHIND THIS ANALYSIS?

A. The $35 million represents a very generous accounting of the the value of Limerick for reliability purposes. A strict adherence to the value of reliability as determined by Mr.

Chernick would yield an even lower reliability portion. I have argued that the remainder of Limerick I belongs in the energy portion. To be consistent, any reductions in the allowed amount of Limerick should lower the amount assigned to the energy component.

Q. IF THE DEMAND COMPONENT IS NOT SUBSTANTIALLY REDUCED FROM WHAT PECO HAS REQUESTED, HOW WILL NON-MANUFACTURING CUSTOMERS LIKELY REACT TO THESE NEW HIGHER DEMAND CHARGES?

A. The non-manufacturing class is very likely to control their loads to conform to the rate signal conveyed by the proposed rate. That is, I expect that the non-manufacturing customers will lower their peak demands by a significant amount. Unfortunately, the end result will be a drastic waste of generating resources and a detriment to both PECo and the remaining customer classes.

Q. COULD YOU PLEASE EXPAND UPON YOUR EXPECTATIONS OF THE NON-MANUFACTURING CLASS AND ITS IMPACT ON PECO?

A. The key to the change in load is that most non-manufacturing customers can either install gas fired air-conditioning or their own generation equipment. Absorption cooling units are commercially available for about $350 per ton and can replace electric compression systems. These units will be quite attractive if the proposed rates are enacted. Alternatively, many customers can install generation equipment for $300 to $500 per KW. Many buildings already have some generation equipment used for backup. If the Company is going to charge $120 per kW for electricity used for to meet extreme air-conditioning loads, then these non-manufacturing establishments can generate their own electricity for a fraction of what PECo charges. In this way, whenever the air-conditioning equipment is called for, the generator will come on and run the air-conditioner. The end result is that the customer has a flat demand and a high load factor and avoids the ratchet and other demand charges. The whole idea of individual customers buying peaking equipment to avoid demand charges makes no sense on a societal basis in the long run. The customers are forced to spend this extra money on redundant generation equipment in order to avoid the demand charges. The customers are reacting properly to an improper pricing signal. The high demand charges signal that PECo is capacity short and will be required to spend large sums of money if peak loads increase. As has been shown, the real cost of additional peak demand is $10.00 per kW. The improper pricing signal leads to the construction of three duplicate sets of generation systems: the plants installed by the customer, Limerick I, and the original peaking plants. This is an unnecessary redundancy of expenditures for which all customers will have to pay.

If the proposed allocation method which assigns all capacity expenses to the demand charge is accepted, then there will be a situation in which the revenue curve does not track the real cost curve. The improper pricing signals that result from the continued use of the four peak allocation method will be disruptive to PECo and its customers. I support the need for rates to track costs, and feel that the Commission must recognize that Limerick costs are energy related and that rates must be adjusted to reflect this.

Q. DOES THIS END YOUR TESTIMONY?

A. Yes it does.

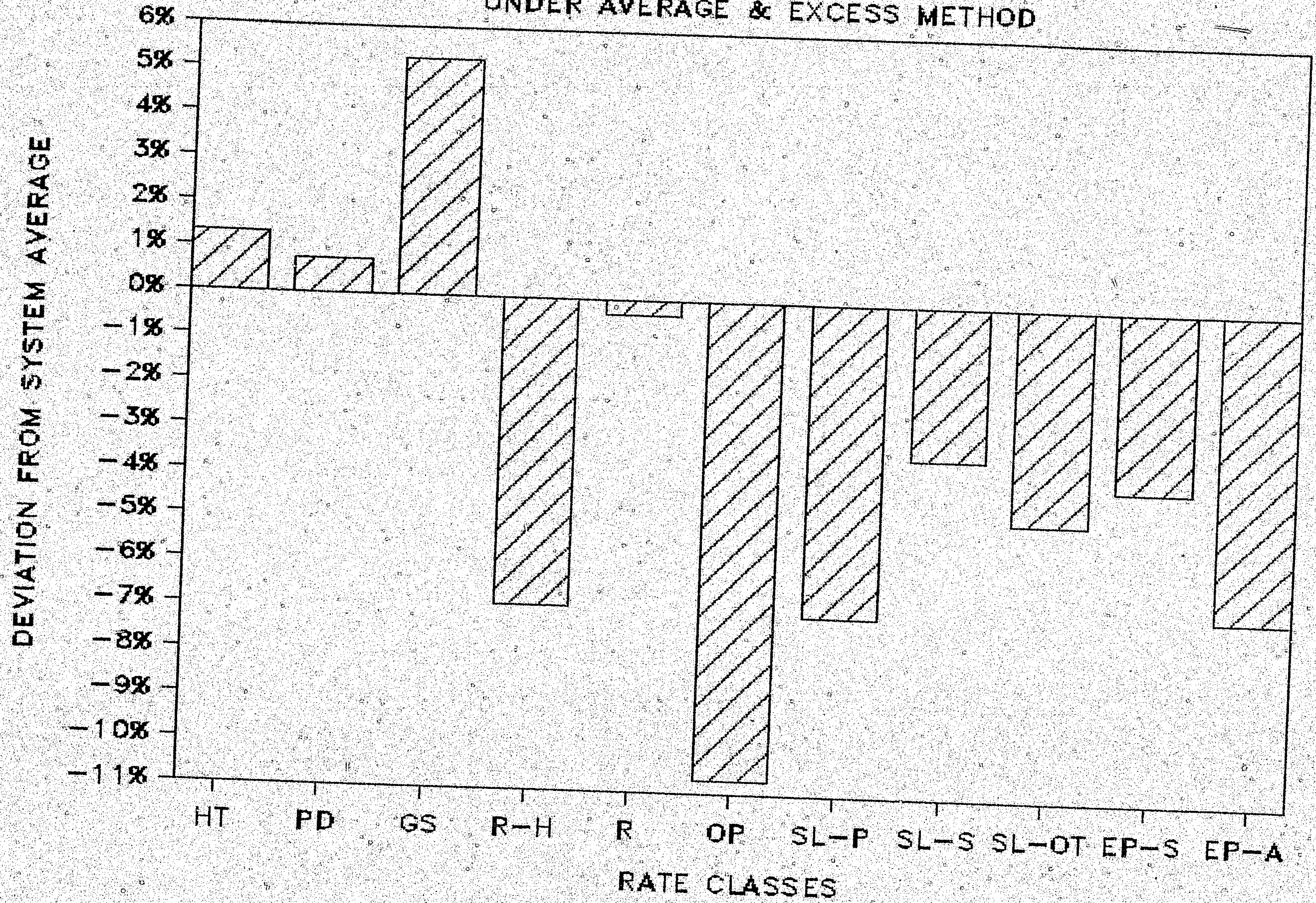
COMPARISON OF 4CP AND AVERAGE/EXCESS COST ALLOCATIONS

RATE CLASS	4CP CLASS RATE OF RETURN (WFS-1, p.6a,b)	AVERAGE/EXCESS CLASS RATE OF RETURN (WFS-1, p.73a,b)	DIFFERENCE BETWEEN A/E AND 4CP
HT	12.23	14.03	1.80
PD	12.40	13.46	1.06
GS	14.70	17.99	3.29
RH	14.69	5.82	-8.87
R	12.15	12.36	0.21
OP	30.98	1.99	-28.99
SLP	12.31	5.68	-6.63
SLS	13.70	9.25	-4.45
OTHER SL	20.51	7.87	-12.64
OTHER UTILITIES	9.55	10.82	1.27
INTER-DEPARTMENTAL	11.16	12.68	1.52
SEPTA	12.70	8.64	-4.06
AMTRAK	12.70	5.81	-6.89

TOTAL 12.70

RATE INCREASE DEVIATION FROM CLOSURE

UNDER AVERAGE & EXCESS METHOD



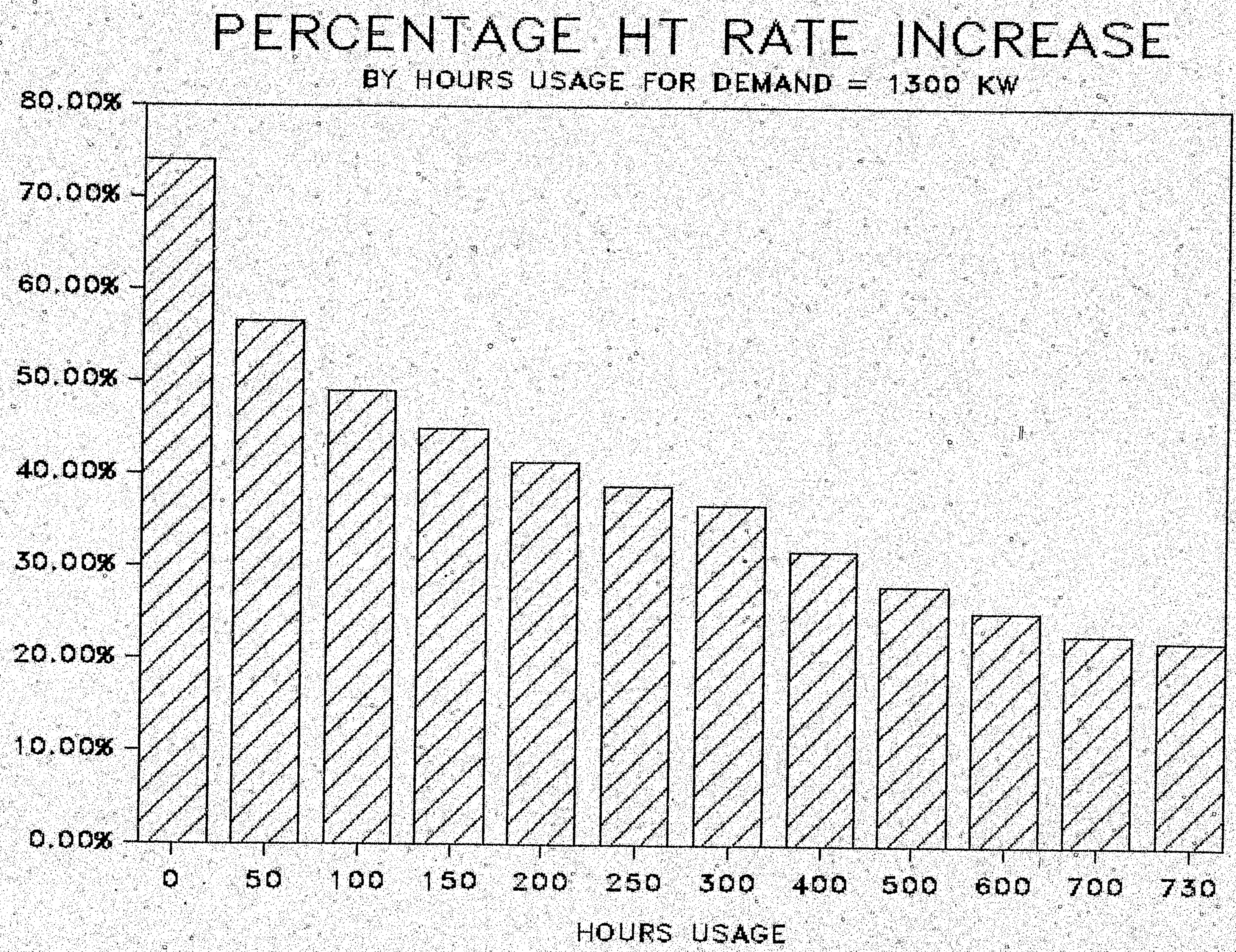
rce: RMW_2, column 4

RMW_3

AWAY FROM CLOSURE UNDER

AVERAGE AND EXCESS METHOD

RATE CLASS	(1) CURRENT CLASS RATE OF RETURN (WFS-1 p. 73a,b line 31)	(2) DEVIATION FROM SYSTEM AVERAGE (Col. 1-6.39)	(3) PROPOSED CLASS RATE OF RETURN (WFS-1 p. 73a,b line 33)	(4) DEVIATION FROM SYSTEM AVERAGE (Col. 3-12.70)	PE INC (TPH-2 col
HT	6.39	0	14.03	1.33	29
PD	6.87	0.48	13.46	0.76	29.
GS	10.18	3.79	17.99	5.29	29.
RH	2.04	-4.39	5.82	-6.88	25.
R	6.26	-0.13	12.36	-0.34	29.
OP	0.50	-5.89	1.99	-10.71	0.
SLP	4.99	-1.40	5.68	-7.02	0.
SLS	8.83	2.44	9.25	-3.45	0.
OTHER SL	7.12	0.73	7.87	-4.83	0.
SEPTA	5.00	-1.39	8.64	-4.02	14.
AMTRAK	3.80	-2.59	5.81	-6.89	12



urce: PECo attachment IV-D-2

RMW_4

BREAKDOWN OF HYPOTHETICAL CUSTOMER USAGE FOR ONE WINTER MONTH WITH & WITHOUT DEMAND RATCHET

CONSUMPTION DATA		PROPOSED RATE STRUCTURE	
actual demand	1000	customer charge	$264.15
billed demand	1500		
summer peak demand	1875	capacity charge	$9.44
billed KWH	500000	energy charges	
		first 150 hrs	$0.0964
		next 150 hrs	$0.0668
		over 300 hrs	$0.0375

CALCULATION OF BILL

	WITH RATCHET			WITHOUT RATCHET			DIFFERENCE		
customer charge			$264.15			$264.15			$0.
billed demand		1500	$14,160.00		1000	$9,440.00		500	$4,720.
energy blocks									
first 150 hrs	(150 X 1500 kw)=	225000	$21,690.00	(150 X 1000 kw)=	150000	$14,460.00	(150 X 500 kw)=	75000	$7,230.
next 150 hrs	(150 X 1500 kw)=	225000	$15,030.00	(150 X 1000 kw)=	150000	$10,020.00	(150 X 500 kw)=	75000	$5,010.
all additional kwh		50000	$1,875.00		200000	$7,500.00		-150000	($5,625.
TOTAL			$53,019.15			$41,684.15			$11,335.

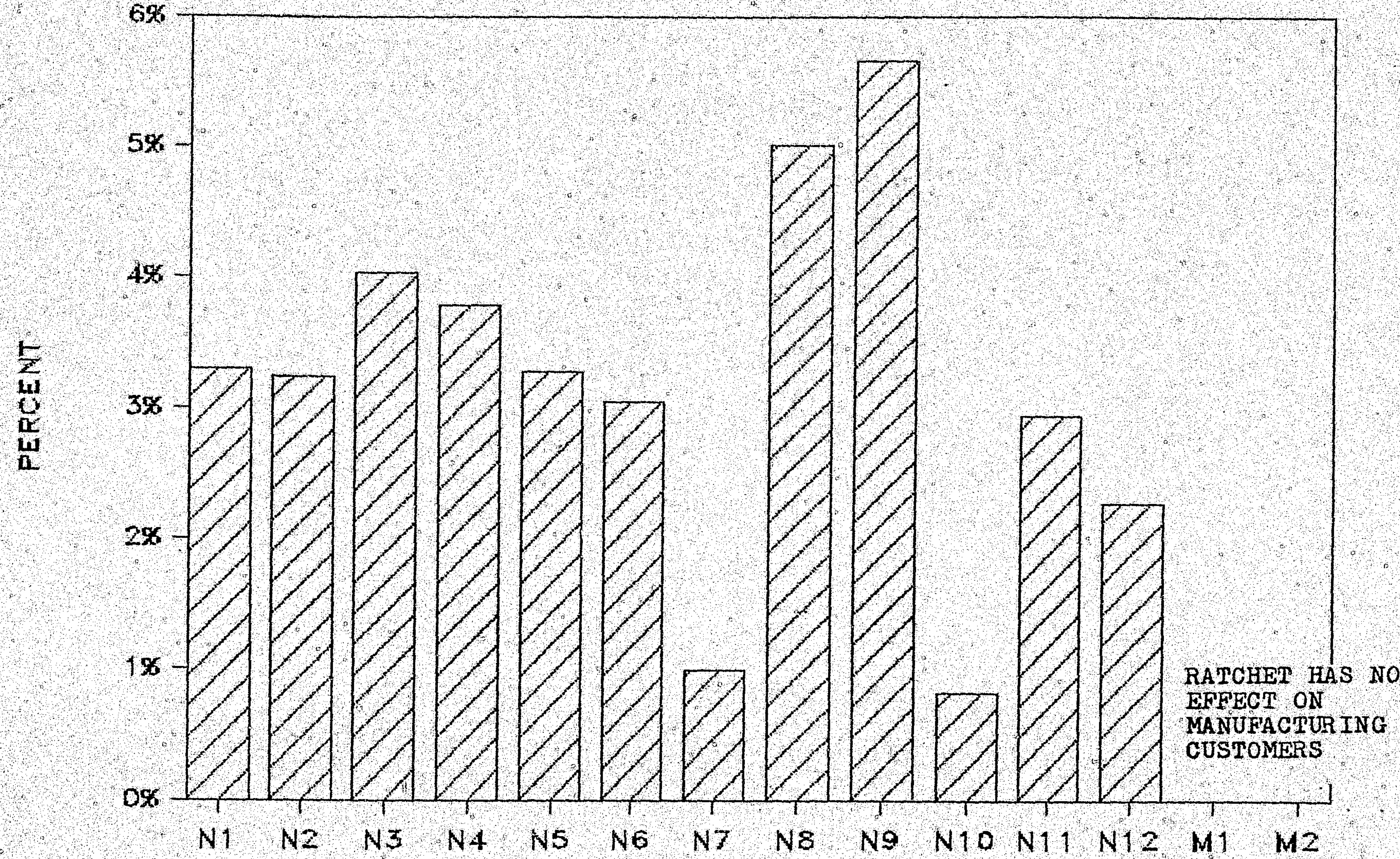
Source: PECo's proposed HT tariff schedule

PROPOSED RATE INCREASE WITH & WITHOUT RATCHET

	PECO new rates	PECO-new rates (no ratchet)	ratchet difference	percent difference due to ratchet
N1	$18,747,700.00	$18,130,820.00	$616,880.00	3.29%
N2	$2,212,831.00	$2,141,140.00	$71,691.00	3.24%
N3	$420,865.50	$403,885.80	$16,979.70	4.03%
N4	$281,610.30	$270,954.60	$10,655.70	3.78%
N5	$295,453.90	$285,781.80	$9,672.10	3.27%
N6	$440,767.10	$427,335.70	$13,431.40	3.05%
N7	$2,293,373.00	$2,270,632.00	$22,741.00	0.99%
N8	$529,924.60	$503,355.60	$26,569.00	5.01%
N9	$939,146.30	$885,936.80	$53,209.50	5.67%
N10	$2,581,688.00	$2,560,472.00	$21,216.00	0.82%
N11	$2,250,113.00	$2,184,075.00	$66,038.00	2.93%
N12	$1,544,731.00	$1,509,626.00	$35,105.00	2.27%
M1	$3,265,059.00	$3,265,059.00	$0.00	0.00%
M2	$27,423,062.00	$27,423,062.00	$0.00	0.00%

PERCENT DIFFERENCE IN PROPOSED RATES

WITH & WITHOUT DEMAND RATCHET



N = NON-MNFG. M = MNFG.

ce: UUC member electric bills
& hypothetical mnfg. bills/
Analysis of PECo rate
request.

RMW 7

ESTIMATION OF IMPACT OF DEMAND RATCHET ON HT BILLED DEMAND

		actual demand	billed demand	difference	power factor as percent of actual	billed demand non-summer without ratchet	KW due to demand ratchet
January	1984	2185147	2358103			2207836	150267
February	1984	2153133	2333586			2175490	158096
March	1984	2052182	2223512			2073491	150021
April	1984	2147970	2313320			2170273	143047
May	1984	2114722	2230481			2136680	93801
June	1984	2352521	2376106	23585	1.0025%		
July	1984	2417812	2441117	23305	0.9639%		
August	1984	2406065	2433563	27498	1.1429%		
September	1984	2340458	2364895	24437	1.0441%		
October	1984	2280959	2344893			2304643	40250
November	1984	1794655	1942972			1813290	129682
December	1984	2303020	2277066			2326933	-49867

average power factor adjustment in summer 1.0384%

yearly HT demand ratcheted KW 815295

ADJUSTMENT OF 1984 BILLED DEMAND DUE TO RATCHET
TO BILLED DEMAND FOR TEST YEAR

1	Additional billed demand due to ratchet for 1984	815295
2	Ratio of total billed demand for 1984 to test year	99.85%
3	Total billed demand 1984 from IR-UUC/UP-4-1	27639614
4	Total billed demand 1985-86 from PECo attachment IV-10 pp. 1-2	
5	HT seven largest customers	3188205
6	Remaining customers	24494179
7	Total HT	27682384
8	Additional billed demand for test year (815295/.9985)	816557

ESTIMATION OF REVENUE COLLECTED FROM DEMAND RATCHET IN HT CLASS

Maximum impact of demand ratchet assuming no customer with less than 300 hours usage.

			pricing	revenue
1 All KW	816557		$9.44	$7,708,294.31
2 first 150 hrs use	122483490	(.0944-.0668)=	$0.0296	$3,625,511.31
3 next 150 hrs use	122483490	(.0668-.0375)=	$0.0293	$3,588,766.26
4		Maximum revenue collected from ratchet		$14,922,571.88

Impact of demand ratchet assuming load characteristics proportional to sampled UUC members.

			pricing	revenue
5 All KW	40406		$9.44	$381,432.64
6 first 150 hrs use	6060900	(.0944-.0668)=	$0.0296	$179,402.64
7 next 150 hrs use	5250000	(.0668-.0375)=	$0.0293	$153,825.00
8 reduction in 2nd block	810900	Maximum revenue collected from ratchet		$714,660.28

9 Total sampled UUC billed KW due to ratchet	40406
10 Total HT billed KW due to ratchet	816557
11 Ratio of sampled UUC billed KW to total HT billed KW due to ratchet	4.95%
12 Total demand ratchet revenue	$14,442,423.63

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13 Changes in HT Blocks

All Changes added to HT exclusive of 7 largest cust.

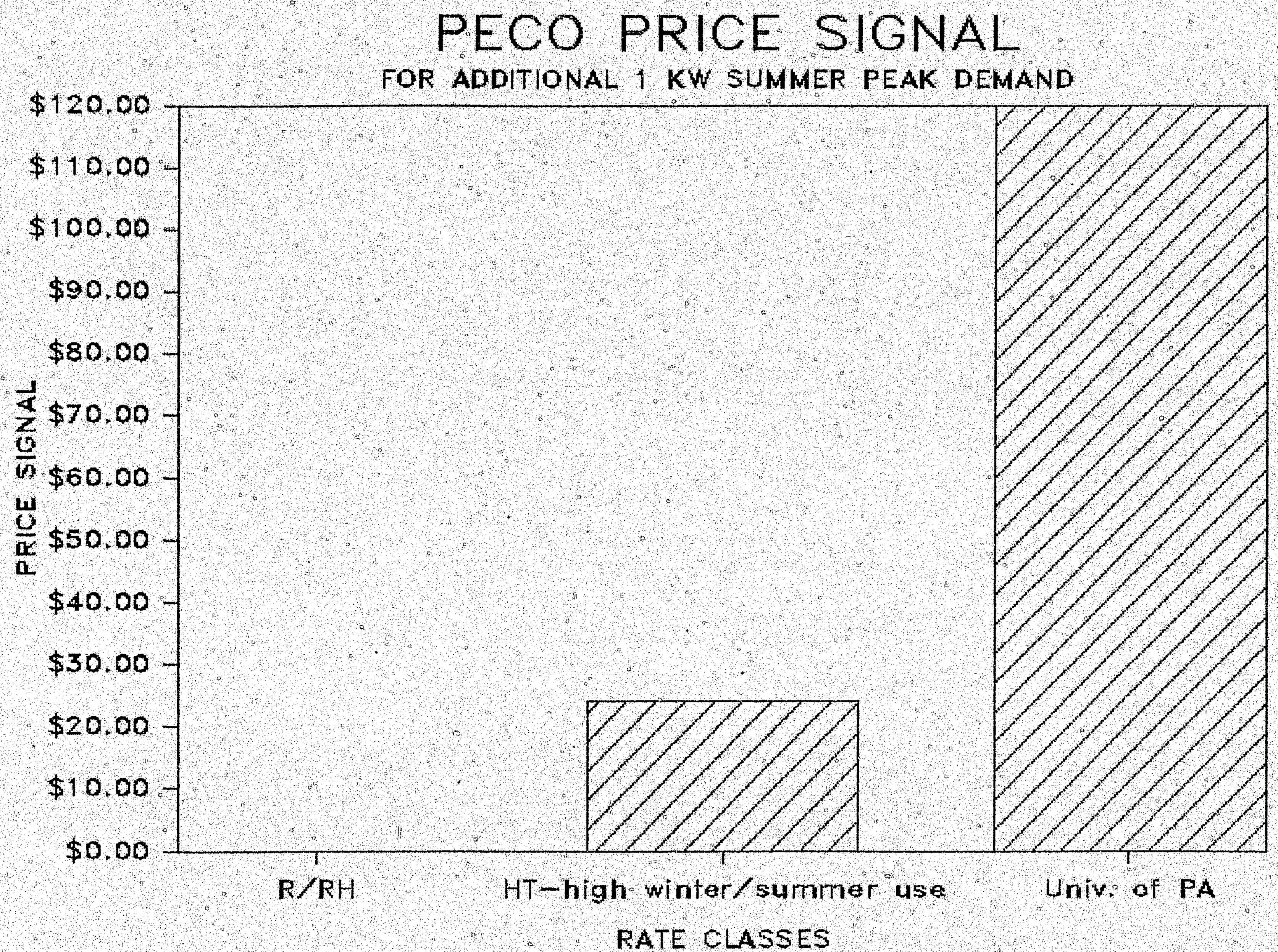
Block	present KWH	change	kwh after ratchet removal
first	3,654,963,716 kwh	(122,483,490)kwh	3,532,480,226
2nd	3,366,781,298 kwh	(122,483,490)Kwh	
		16,381,818 kwh	3,260,679,626
3rd	3,019,493,022	244,966,980 kwh	
		(16,381,818)kwh	3,248,078,184

THE PRICE SIGNAL GIVEN TO VARIOUS PECO RATE CLASSES
For adding 1 kw of additional summer peak demand

Class	price signal/kw
R, RH	$0.00
HT high winter and summer user	$24.00 (1)
Univ. of PA	$120.00
Cost of adding additional peaking capacity (per kw)	$5.00 (2)

(1) $9.44 demand charge + 150 ($0.0964-0.0375) + 150 ($0.0668-0.0375) multiplied by 1.0586 STAC

(2) From IR-oca-15-5 Cost of maintaining peaking plants



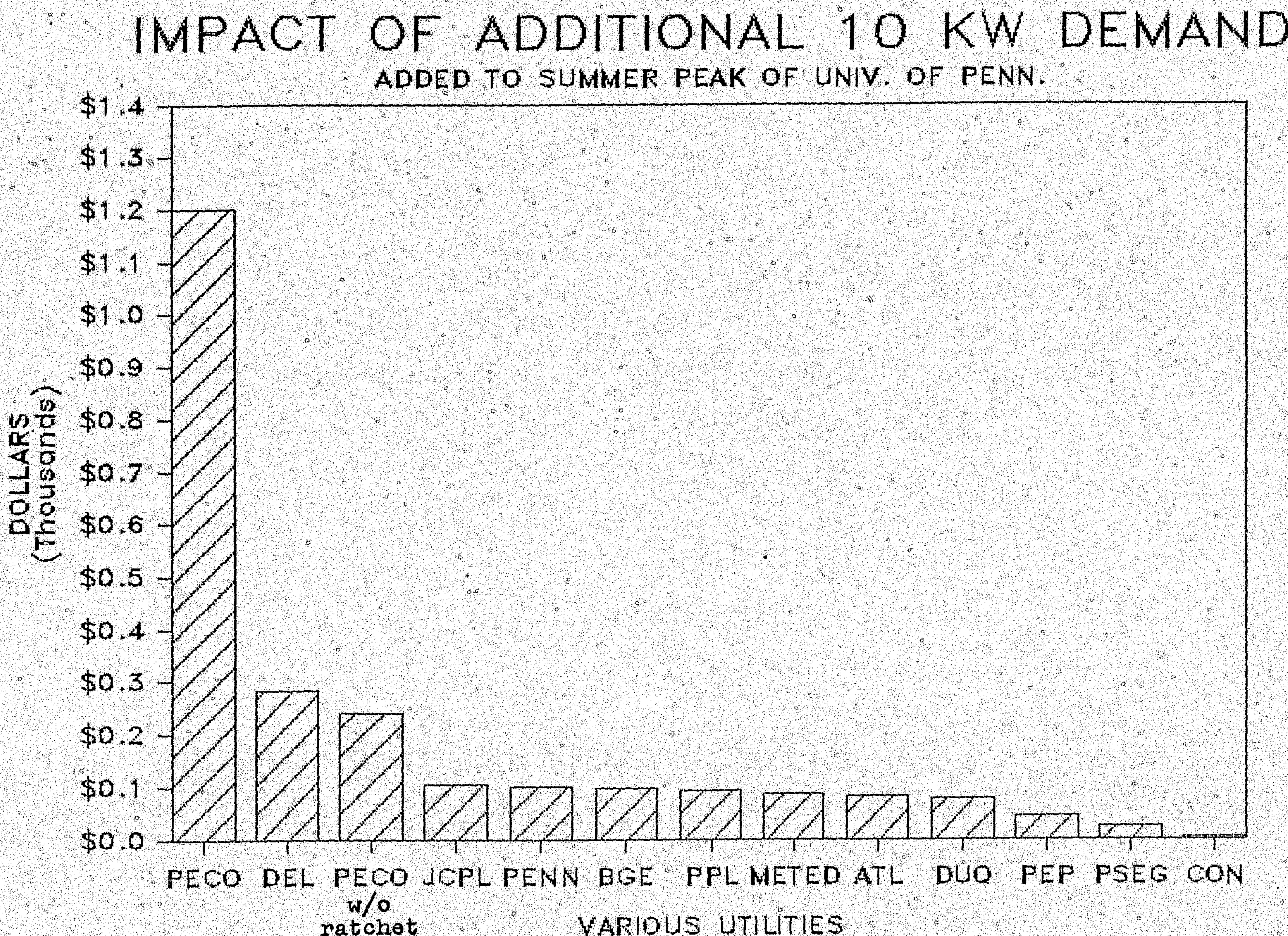
Source: RMW_11

RMW_12

IMPACT OF 10 KW INCREASE IN DEMAND IN PEAK SUMMER MONTH
FOR UNIVERSITY OF PENNSYLVANIA

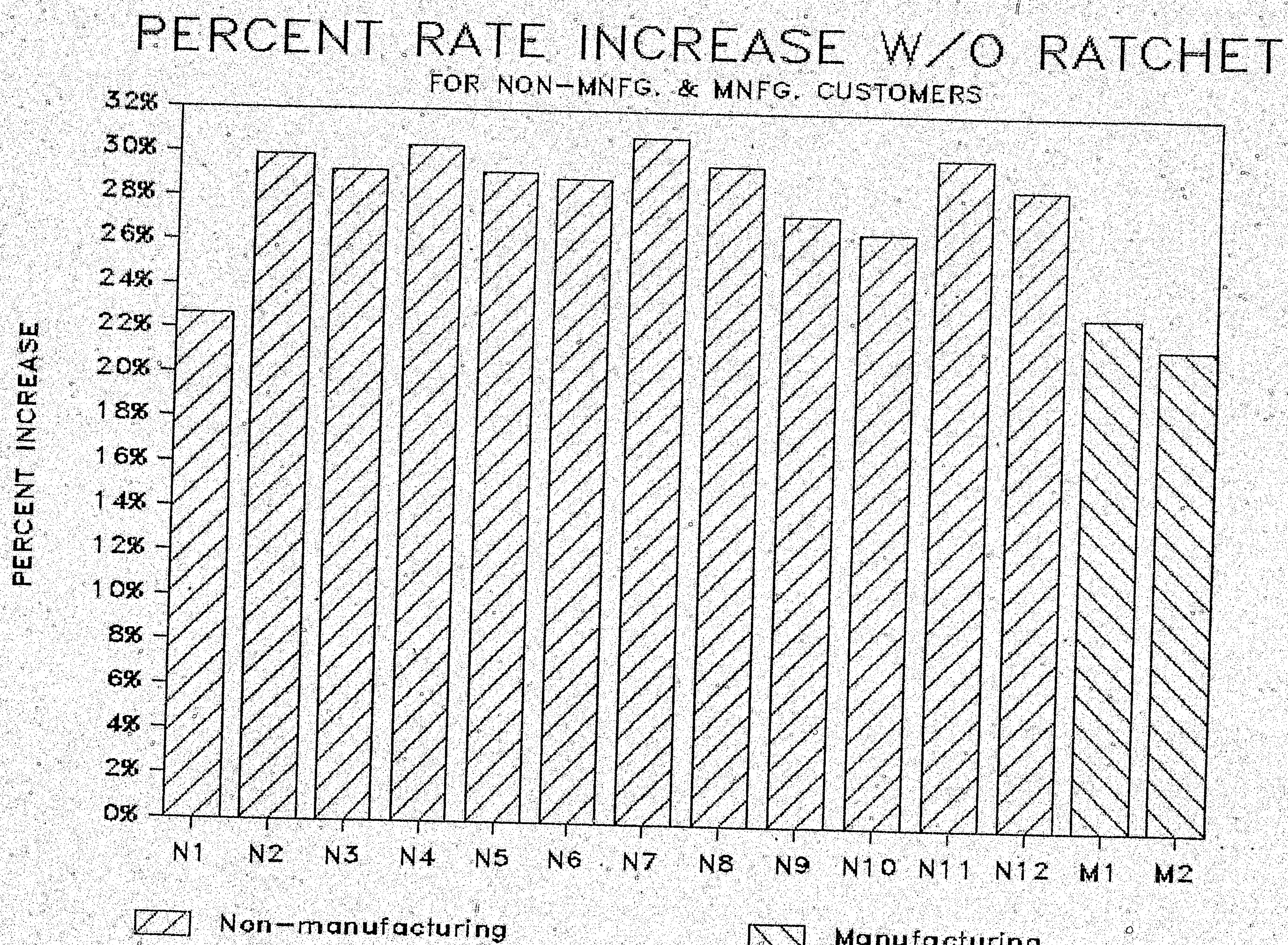
impact of 10 kw demand increase	utility	without demand increase	with 10 kw demand increase
$1,200	PECO	$18,747,700	$18,748,900
$282	DEL	$11,133,222	$11,133,504
$240	PECO**	$18,130,820	$18,131,060
$103	JCPL	$17,206,368	$17,206,471
$101	PENN	$10,810,643	$10,810,744
$98	BGE	$10,048,478	$10,048,576
$92	PPL	$11,771,491	$11,771,583
$87	METED	$11,016,106	$11,016,193
$82	ATL	$14,013,511	$14,013,593
$76	DUQ	$10,576,070	$10,576,146
$44	PEP	$11,450,754	$11,450,798
$24	PSEG	$12,228,310	$12,228,334
$2	CON	$13,587,501	$13,587,503

**without ratchet



urce: Utility rate schedule analysis & Univ. of PA electric bills.

RMW 14



urce: UUC member electric bills & hypothetical mnfg. bills/ Analysis of PECo rate request.

RMW 15

CHANGES IN TOTAL ANNUAL UNIT COST-TO-SERVE
IF LIMERICK IS TREATED AS ENERGY RELATED COST
90% allocated to energy
HIGH TENSION CLASS--TWELVE MONTHS ENDED 6/30/86
(in thousand dollars)

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1 Revenue Requirement for Limerick
and Common- (PECo ST. # 18, Table $858,170 — Portion Allowed 100.00%
Portion transfered to energy component 90.00%

2 Percentage of Limerick assigned to HT
(WFS-1, p.29 A1 Allocation) 41.462%

3 Limerick Revenue Requirement HT Class
(line 1 multiplied by line 2) $355,814 — TRANSFERRED PORTION $320,233

	Total Class (1)	4 Peak (2)	Class Peak (3)	Energy (4)	Customer (5)
4 Total Annual Revenue Requirement PECo Method (IR-PAIEUG-1-50)	$1,142,725	$772,779	$25,602	$336,975	$7,369
5 Limerick Adjustment (line 3)	$0	($320,233)		$320,233	
6 Total Annual Revenue Requirement UUC Method Before Ratchet Removal	$1,142,725	$452,546	$25,602	$657,208	$7,369
7 Total Demand Ratchet Revenue (RMW_10, line 12)		($14,442)		$14,442	
8 Total Annual Revenue Requirement UUC Method After Ratchet Removal	$1,142,725	$438,104	$25,602	$671,650	$7,369
9 Cost Function Divisor (Ir-PAIEUG 1-50)		2135188	2381938	12947425	2316
10 Minus Billed Demand due to Ratchet (RMW_9, line 8/12months)			68046		
11 Cost Function Divisor without ratchet		2135188	2313892	12947425	2316
12 Total Unit Annual Cost to Serve ($/KW,$/KWH,$/CUST) (line 8 divided by line 12)		205.18287	11.06448	0.05188	3181.78
13 Demand Component For HT Rate (ln. 8 cols. (2 + 3)/ln. 11, col. 3)	200.40				

DERIVATION OF HT RATES USING UUC ADJUSTMENT FOR LIMERICK AS ENERGY COMPONENT
RECALCULATED WORKSHEET FOR DERIVING HT RATES
(as calculated in IR-PAIEUG-1-50)

Year 1985-tariff 26, #3, systems return
H.T. CLASS

HOURS USE	F(M)	ENERGY CMPNT	DEMAND CMPNT	CUSTOMER COMPONENT 100	500	1300	50000	0	0	TOTAL COST TO SERVE 100	500	1300	50000	0	
		5.19	200.40			3181.78									
0	0.0	0.00	0.00	2.65	0.53	0.20	0.01	0.0	0.0	2.65	0.53	0.20	0.01	0.0	0.
50	0.266	2.59	4.44	2.65	0.53	0.20	0.01	0.0	0.0	9.69	7.57	7.24	7.04	0.0	0
100	0.432	5.19	7.21	2.65	0.53	0.20	0.01	0.0	0.0	15.05	12.93	12.61	12.41	0.0	0
150	0.558	7.78	9.32	2.65	0.53	0.20	0.01	0.0	0.0	19.75	17.63	17.30	17.11	0.0	0
200	0.66	10.38	11.02	2.65	0.53	0.20	0.01	0.0	0.0	24.05	21.93	21.60	21.40	0.0	0
250	0.73	12.97	12.19	2.65	0.53	0.20	0.01	0.0	0.0	27.81	25.69	25.36	25.17	0.0	0
300	0.778	15.56	12.99	2.65	0.53	0.20	0.01	0.0	0.0	31.21	29.09	28.76	28.56	0.0	0
400	0.829	20.75	13.84	2.65	0.53	0.20	0.01	0.0	0.0	37.25	35.12	34.80	34.60	0.0	0
500	0.854	25.94	14.26	2.65	0.53	0.20	0.01	0.0	0.0	42.85	40.73	40.40	40.20	0.0	0
600	0.907	31.13	15.15	2.65	0.53	0.20	0.01	0.0	0.0	48.92	46.80	46.48	46.28	0.0	0
700	0.969	36.31	16.18	2.65	0.53	0.20	0.01	0.0	0.0	55.15	53.03	52.70	52.50	0.0	0
730	1.000	37.87	16.70	2.65	0.53	0.20	0.01	0.0	0.0	57.22	55.10	54.77	54.57	0.0	0

SLOPE OF COST TO SERVE VS. HOURS USE CURVE

HOURS USE	TOTAL COST TO SERVE 100	500	1300	50000	0	0	AVERAGE SLOPE
100-150	.093959	0.093959	0.093959	0.093959	0	0	0.093959
150-300	.076368	0.076368	0.076368	0.076368	0	0	0.076368
300-600	.059056	0.059056	0.059056	0.059056	0	0	0.059056

PHILADELPHIA ELECTRIC COMPANY-ELECTRIC OPERATIONS

RATE HT--7 LARGE CUSTOMERS

CALCULATION OF REVENUE INCREASE UUC METHOD

12 MONTHS ENDED
JUNE 30, 1985 & 1986

12 MONTHS SAMPLE	BILLS, KW AND KWH FROM SAMPLE	SUPPLEMENT NO. 11 PRICING	SUPPLEMENT NO. 11 REVENUE	BILLS, KW AND KWH FROM SAMPLE	UUC SUPPLEMENT PRICING	UUC SUPPLEMENT REVENUE
	(1)	(2)	(3)=(1)*(2)	(4)	(5)	(6)=(4)*(5)
1 CUSTOMER CHARGE	84 BILLS	$220.45	$18,518	84 BILLS	$264.15	$22,189
2 ALL KW	3,188,205 KW	5.37	$17,120,661	3,188,205 KW	5.77	$18,395,943
3 FIRST 150 HRS USE	478,230,000 KWH	0.0739	$35,341,197	478,230,000 KWH	0.0940	$44,953,620
4 NEXT 150 HRS USE	448,837,000 KWH	0.0556	$24,955,337	448,837,000 KWH	0.0764	$34,291,147
5 ADDITIONAL USE	1,411,512,000 KWH	0.0376	$53,072,851	1,411,512,000 KWH	0.0591	$83,420,359
6 HIGH VOLTAGE DISCOUNT	2,527,620 KWH	0.3	($758,286)	2,527,620 KWH	0.3	($758,286)
7 BASE REVENUE			$129,750,278			$180,324,971

PHILADELPHIA ELECTRIC COMPANY-ELECTRIC OPERATIONS

RATE HT

CALCULATION OF REVENUE INCREASE UUC METHOD

12 MONTHS ENDED
JUNE 30, 1985 & 1986

	SUPPLEMENT NO. 11				UUC SUPPLEMENT	
12 MONTHS SAMPLE	BILLS, KW AND KWH FROM SAMPLE	PRICING	REVENUE	BILLS, KW AND KWH FROM SAMPLE	PRICING	REVENUE
	(1)	(2)	(3)=(1)*(2)	(4)	(5)	(6)=(4)*(5)
1 CUSTOMER CHARGE	27,512 BILLS	$220.45	$6,065,020	27,512 BILLS	$264.15	$7,267,295
2 ALL KW	24,494,179 KW	5.37	$131,533,741	23,677,622 KW (A)	5.77	$136,619,879
3 FIRST 150 HRS USE	3,654,963,716 KWH	0.0739	$270,101,819	3,532,480,166 KWH (B)	0.0940	$332,053,136
4 NEXT 150 HRS USE	3,366,781,298 KWH	0.0556	$187,193,040	3,356,134,112 KWH (C)	0.0764	$256,408,646
5 ADDITIONAL USE	3,019,493,022 KWH	0.0376	$113,532,938	3,152,623,758 KWH (D)	0.0591	$186,320,064
Total kwh	10,041,238,036 KWH			10,041,238,036		
6 HIGH VOLTAGE DISCOUNT > 66KV			($22,128)			($22,128)
7 HIGH VOLTAGE DISCOUNT - 66KV			($81,385)			($81,385)
8 HIGH VOLTAGE DISCOUNT - 33KV			($606,481)			($606,481)
9 SUB-TOTAL			$707,716,564			$917,959,026
10 UNACCOUNTED FOR			$99,292			$128,789
11 BASE REVENUE			$707,815,856			$918,087,814
TOTAL RATE HT-----------12 MOS. ENDED 6/30/85						
12 PROFORMA BASE REVENUE-EXCL NSR & 7 LARGE CUSTS			$714,950,596			$927,342,083
13 NIGHT SERVICE RIDER			$3,520,126			$3,520,126
14 BASE REVENUE OF 7 LARGE CUSTS			$129,750,278			$180,324,971
15 TOTAL PROFORMA BASE REVENUE			$848,221,000			$1,111,187,180
16 CURTAILMENT RIDER			($113,000)			($113,000)
17 ADJUSTED BASE REVENUE			$848,108,000			$1,111,074,180
TOTAL RATE HT-----------12 MOS. ENDED 6/30/86						
18 BASE REVENUE			$860,983,000			$1,127,905,666
19 CURTAILMENT RIDER			$0			($113,000)
20 ADJUSTED BASE REVENUE			$860,983,000			$1,127,792,666

(A) (LN.2,COL.1 - BILLED DEMAND FROM RATCHET, RMW #,LN. 8)
(B) (LN.3,COL.1 - RMW # ,LN.13)
(C) (LN.4,COL.1 - RMW # ,LN. 14)
(D) (LN.5, COL.1 - RMW # , LN.15)

PHILADELPHIA ELECTRIC COMPANY -- ELECTRIC OPERATIONS

COMPARISON OF MONTHLY BILLS

RATE: HT USING UUC ADJUSTMENTS DEMAND = 500

HRS USAGE	BASE RATE BILL EXISTING RATE	PROPOSED RATE	$ CHANGE	% CHANGE	TOTAL BILL EXISTING RATE	PROPOSED RATE	$ CHANGE	% CHANGE
0	2905	3149	244	8.4%	3079	3334	255	8.3%
10	3275	3619	344	10.5%	3484	3845	361	10.4%
20	3644	4089	445	12.2%	3889	4356	467	12.0%
30	4014	4559	545	13.6%	4294	4867	573	13.3%
40	4383	5029	646	14.7%	4699	5378	679	14.4%
50	4753	5499	746	15.7%	5104	5889	785	15.4%
60	5122	5969	847	16.5%	5509	6400	891	16.2%
70	5492	6439	947	17.2%	5914	6911	997	16.9%
80	5861	6909	1048	17.9%	6319	7422	1103	17.4%
90	6231	7379	1148	18.4%	6724	7933	1209	18.0%
100	6600	7849	1249	18.9%	7129	8444	1315	18.4%
150	8448	10199	1751	20.7%	9155	10999	1845	20.1%
200	9839	12109	2271	23.1%	10695	13089	2393	22.4%
250	11228	14019	2791	24.9%	12236	15178	2942	24.0%
300	12618	15929	3311	26.2%	13776	17268	3491	25.3%
400	14498	18884	4386	30.3%	15903	20531	4627	29.1%
500	16378	21839	5461	33.3%	18031	23794	5763	32.0%
600	18258	24794	6536	35.8%	20158	27057	6899	34.2%
700	20138	27749	7611	37.8%	22285	30320	8035	36.1%
730	20702	28636	7934	38.3%	22923	31299	8376	36.5%

CHANGES IN TOTAL ANNUAL UNIT COST-TO-SERVE RMW__21
IF LIMERICK IS TREATED AS ENERGY RELATED COST
$35,581,400 allocated to DEMAND, remainder to ENERGY, 50% allowed in rate base energy
HIGH TENSION CLASS--TWELVE MONTHS ENDED 6/30/86
(in thousand dollars)

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1 Revenue Requirement for Limerick
and Common- (PECo ST. # 18, Table $858,170 Portion Allowed 50.00%

2 Percentage of Limerick assigned to HT
(WFS-1, p.29 A1 Allocation) 41.462%

3 Limerick Revenue Requirement HT Class
(line 1 multiplied by line 2) $177,907 TRANSFERRED PORTION

	Total Class (1)	4 Peak (2)	Class Peak (3)	Energy (4)	Customer (5)
4 Total Annual Revenue Requirement PECo Method (IR-PAIEUG-1-50)	$1,142,725	$772,779	$25,602	$336,975	$7,369
5 Limerick Adjustment (line 3)	($177,907)	($320,233)		$142,326	
6 Total Annual Revenue Requirement UUC Method Before Ratchet Removal	$964,818	$452,546	$25,602	$479,301	$7,369
7 Total Demand Ratchet Revenue (RMW_10, line 12)		($14,442)		$14,442	
8 Total Annual Revenue Requirement UUC Method After Ratchet Removal	$964,818	$438,104	$25,602	$493,743	$7,369
9 Cost Function Divisor (Ir-PAIEUG 1-50)		2135188	2381938	12947425	2316
10 Minus Billed Demand due to Ratchet (RMW_9, line 8/12months)			68046		
11 Cost Function Divisor without ratchet		2135188	2313892	12947425	2316
12 Total Unit Annual Cost to Serve ($/KW,$/KWH,$/CUST) (line 8 divided by line 12)		205.18287	11.06448	0.03813	3181.78
13 Demand Component For HT Rate (ln. 8 cols. (2 + 3)/ln. 11, col. 3)	200.40				

DERIVATION OF HT RATES USING UUC ADJUSTMENT FOR LIMERICK AS ENERGY COMPONENT
RECALCULATED WORKSHEET FOR DERIVING HT RATES
(as calculated in IR-PAIEUG-1-50)
Only 50% of Limerick allowed in rate base

Year 1985-tariff 26, #3, systems return
H.T. CLASS

HOURS USE	F(M)	ENERGY CMPNT	DEMAND CMPNT	CUSTOMER COMPONENT 100	500	1300	50000	0	0	TOTAL COST TO SERVE 100	500	1300	50000	0	
		3.81	200.40			3181.78									
0	0.0	0.00	0.00	2.65	0.53	0.20	0.01	0.0	0.0	2.65	0.53	0.20	0.01	0.0	0.
50	0.266	1.91	4.44	2.65	0.53	0.20	0.01	0.0	0.0	9.00	6.88	6.55	6.35	0.0	0.
100	0.432	3.81	7.21	2.65	0.53	0.20	0.01	0.0	0.0	13.68	11.56	11.23	11.03	0.0	0.
150	0.558	5.72	9.32	2.65	0.53	0.20	0.01	0.0	0.0	17.69	15.57	15.24	15.04	0.0	0.
200	0.66	7.63	11.02	2.65	0.53	0.20	0.01	0.0	0.0	21.30	19.18	18.85	18.65	0.0	0.
250	0.73	9.53	12.19	2.65	0.53	0.20	0.01	0.0	0.0	24.38	22.25	21.93	21.73	0.0	0.
300	0.778	11.44	12.99	2.65	0.53	0.20	0.01	0.0	0.0	27.08	24.96	24.64	24.44	0.0	0.
400	0.829	15.25	13.84	2.65	0.53	0.20	0.01	0.0	0.0	31.75	29.63	29.30	29.10	0.0	0.
500	0.854	19.07	14.26	2.65	0.53	0.20	0.01	0.0	0.0	35.98	33.86	33.53	33.33	0.0	0.
600	0.907	22.88	15.15	2.65	0.53	0.20	0.01	0.0	0.0	40.68	38.56	38.23	38.03	0.0	0.
700	0.969	26.69	16.18	2.65	0.53	0.20	0.01	0.0	0.0	45.53	43.41	43.08	42.88	0.0	0.
730	1.000	27.84	16.70	2.65	0.53	0.20	0.01	0.0	0.0	47.19	45.07	44.74	44.54	0.0	0.

SLOPE OF COST TO SERVE VS. HOURS USE CURVE

HOURS USE	TOTAL COST TO SERVE 100	500	1300	50000	0	0	AVERAGE SLOPE
100-150	.080218	0.080218	0.080218	0.080218	0	0	0.080218
150-300	.062627	0.062627	0.062627	0.062627	0	0	0.062627
300-600	.045315	0.045315	0.045315	0.045315	0	0	0.045315

PHILADELPHIA ELECTRIC COMPANY-ELECTRIC OPERATIONS

RATE HT--7 LARGE CUSTOMERS

CALCULATION OF REVENUE INCREASE UUC METHOD

Only 50% of Limerick allowed in rate base

12 MONTHS ENDED
JUNE 30, 1985 & 1986

	SUPPLEMENT NO. 11			UUC SUPPLEMENT		
12 MONTHS SAMPLE	BILLS, KW AND KWH FROM SAMPLE	PRICING	REVENUE	BILLS, KW AND KWH FROM SAMPLE	PRICING	REVENUE
	(1)	(2)	(3)=(1)*(2)	(4)	(5)	(6)=(4)*(5)
1 CUSTOMER CHARGE	84 BILLS	$220.45	$18,518	84 BILLS	$264.15	$22,189
2 ALL KW	3,188,205 KW	5.37	$17,120,661	3,188,205 KW	*	$0
3 FIRST 150 HRS USE	478,230,000 KWH	0.0739	$35,341,197	478,230,000 KWH	0.0802	$38,354,046
4 NEXT 150 HRS USE	448,837,000 KWH	0.0556	$24,955,337	448,837,000 KWH	0.0626	$28,097,196
5 ADDITIONAL USE	1,411,512,000 KWH	0.0376	$53,072,851	1,411,512,000 KWH	0.0453	$63,941,494
6 HIGH VOLTAGE DISCOUNT	2,527,620 KWH	0.3	($758,286)	2,527,620 KWH	0.3	($758,286)
7 BASE REVENUE			$129,750,278			$129,656,638

PHILADELPHIA ELECTRIC COMPANY-ELECTRIC OPERATIONS

RATE HT

CALCULATION OF REVENUE INCREASE UUC METHOD

Only 50% of Limerick allowed in rate base — 12 MONTHS ENDED JUNE 30, 1985 &1986

12 MONTHS SAMPLE	BILLS, KW AND KWH FROM SAMPLE	SUPPLEMENT NO. 11 PRICING	SUPPLEMENT NO. 11 REVENUE	BILLS, KW AND KWH FROM SAMPLE	UUC SUPPLEMENT PRICING	UUC SUPPLEMENT REVENUE
	(1)	(2)	(3)=(1)*(2)	(4)	(5)	(6)=(4)*(5)
1 CUSTOMER CHARGE	27,512 BILLS	$220.45	$6,065,020	27,512 BILLS	$264.15	$7,267,295
2 ALL KW	24,494,179 KW	5.37	$131,533,741	23,677,622 KW (A)	5.14	$121,702,977
3 FIRST 150 HRS USE	3,654,963,716 KWH	0.0739	$270,101,819	3,532,480,166 KWH (B)	0.0802	$283,304,909
4 NEXT 150 HRS USE	3,366,781,298 KWH	0.0556	$187,193,040	3,356,134,112 KWH (C)	0.0626	$210,093,995
5 ADDITIONAL USE	3,019,493,022 KWH	0.0376	$113,532,938	3,152,623,758 KWH (D)	0.0453	$142,813,856
Total kwh	10,041,238,036 KWH			10,041,238,036		
6 HIGH VOLTAGE DISCOUNT > 66KV			($22,128)			($22,128)
7 HIGH VOLTAGE DISCOUNT - 66KV			($81,385)			($81,385)
8 HIGH VOLTAGE DISCOUNT - 33KV			($606,481)			($606,481)
9 SUB-TOTAL			$707,716,564			$764,473,039
10 UNACCOUNTED FOR			$99,292			$107,255
11 BASE REVENUE			$707,815,856			$764,580,294
TOTAL RATE HT-----------12 MOS. ENDED 6/30/85						
12 PROFORMA BASE REVENUE-EXCL NSR & 7 LARGE CUSTS			$714,950,596			$772,287,216
13 NIGHT SERVICE RIDER			$3,520,126			$3,520,126
14 BASE REVENUE OF 7 LARGE CUSTS			$129,750,278			$129,656,638
15 TOTAL PROFORMA BASE REVENUE			$848,221,000			$905,463,980
16 CURTAILMENT RIDER			($113,000)			($113,000)
17 ADJUSTED BASE REVENUE			$848,108,000			$905,350,980
TOTAL RATE HT-----------12 MOS. ENDED 6/30/86						
18 BASE REVENUE			$860,983,000			$919,087,235
19 CURTAILMENT RIDER			$0			($113,000)
20 ADJUSTED BASE REVENUE			$860,983,000			$918,974,235

(A) (LN.2,COL.1 - BILLED DEMAND FROM RATCHET, RMW #,LN. 8)
(B) (LN.3,COL.1 - RMW # ,LN.13)
(C) (LN.4,COL.1 - RMW # ,LN. 14)
(D) (LN.5, COL.1 - RMW # , LN.15)

PHILADELPHIA ELECTRIC COMPANY -- ELECTRIC OPERATIONS

COMPARISON OF MONTHLY BILLS

RATE: HT USING UUC ADJUSTMENTS DEMAND = 500
Only 50% of Limerick allowed in rate base

	BASE RATE BILL				TOTAL BILL			
HRS USAGE	EXISTING RATE	PROPOSED RATE	$ CHANGE	% CHANGE	EXISTING RATE	PROPOSED RATE	$ CHANGE	% CHANGE
0	2905	2834	-71	-2.5%	3079	3000	-79	-2.6%
10	3275	3235	-40	-1.2%	3484	3438	-46	-1.3%
20	3644	3636	-8	-0.2%	3889	3876	-13	-0.3%
30	4014	4037	23	0.6%	4294	4314	20	0.5%
40	4383	4438	55	1.2%	4699	4752	53	1.1%
50	4753	4839	86	1.8%	5104	5190	86	1.7%
60	5122	5240	118	2.3%	5509	5628	119	2.2%
70	5492	5641	149	2.7%	5914	6066	152	2.6%
80	5861	6042	181	3.1%	6319	6504	185	2.9%
90	6231	6443	212	3.4%	6724	6942	218	3.2%
100	6600	6844	244	3.7%	7129	7380	251	3.5%
150	8448	8849	401	4.7%	9155	9570	415	4.5%
200	9838	10414	576	5.9%	10695	11294	599	5.6%
250	11228	11979	751	6.7%	12236	13019	783	6.4%
300	12618	13544	926	7.3%	13776	14743	967	7.0%
400	14498	15809	1311	9.0%	15903	17276	1372	8.6%
500	16378	18074	1696	10.4%	18031	19808	1778	9.9%
600	18258	20339	2081	11.4%	20158	22341	2183	10.8%
700	20138	22604	2466	12.2%	22285	24874	2589	11.6%
730	20702	23284	2582	12.5%	22923	25634	2710	11.8%

N1

	jan	feb	march	april	may	june	july	aug	sept	oct	nov	dec
bill days	30	30	30	30	30	30	30	30	30	30	30	30
billed kwh	14760200	14090600	15617900	15495800	16730800	19324700	20749900	20451800	19257700	19474600	17030400	15319200
actual demand	25776	25992	26064	28944	33696	33912	36720	36504	40176	37584	33768	28224
billed demand	32141	32141	32141	32141	33696	33912	36720	36504	40176	37584	33768	32141
power factor	95	95	95	95	95	95	95	95	95	95	95	95
on-peak kwh	5203404	5637456	5247612	6023988	6584868	6770268	7416174	8148823	7224277	7133414	6508044	5742432
off-peak kwh	9556796	8453144	10370288	9471812	10145932	12554432	13333726	12302977	12033423	12341186	10522356	9576768
voltage	13200											
previous demand	26568	25200	25992	26712	29592	35208	34992	35856	36792	37584	34488	27360

N2

	jan	feb	march	april	may	june	july	aug	sept	oct	nov	dec
bill days	30	30	30	30	30	30	30	30	30	30	30	30
billed kwh	1115000	1203000	1184000	1378000	1594000	1522000	1641000	1637000	1859000	1505000	1411000	1434000
actual demand	2951	3002	4242	4533	4547	4670	5233	5106	5090	4759	4453	3959
billed demand	4347	4347	4347	4533	4547	4670	5233	5106	5090	4759	4453	4347
power factor	95	95	95	95	95	95	95	95	95	95	95	95
on-peak kwh	590471	556153	641377	702571	824903	875598	953238	933920	971870	799303	710809	694988
off-peak kwh	524259	646847	542623	675429	769097	646402	687762	703060	887130	705697	700191	739012
voltage	13200											
previous demand	3023	3052	3832	4336	4739	5222	5198	5102	4900	4643	4444	4339

N3

	jan	feb	march	april	may	june	july	aug	sept	oct	nov	dec
bill days	30	30	30	30	30	30	30	30	30	30	30	30
billed kwh	254600	235000	217100	250500	295000	295700	315700	351700	318700	240400	278300	256500
actual demand	615	574	594	844	967	908	1004	1040	1053	857	834	626
billed demand	774	774	774	844	967	908	1004	1040	1053	857	834	774
power factor	90	90	90	90	90	90	90	90	90	90	90	90
on-peak kwh	117879.8	104575	104859.3	125751	156940	154355.4	177739.1	185697.6	159350	114190	133027.4	120555
off-peak kwh	136720.2	130425	112240.7	124749	138060	141344.6	137960.9	166002.4	159350	126210	145272.6	135945
voltage	13200											
previous demand	624	603	522	740	996	967	912	927	879	867	800	632

N4

	jan	feb	march	april	may*	june	july	aug	sept	oct	nov	dec
bill days	30	30	30	30	30	30	30	30	30	30	30	30
billed kwh	196100	184300	150300	157100	186800	182500	220700	205900	204200	139500	151700	154300
actual demand	648	504	441	576	606	603	657	648	666	486	477	459
billed demand	648	605	605	605	606	603	657	648	666	526	526	605
power factor	90	90	90	90	90	90	90	90	90	90	90	90
on-peak kwh	90794.3	82013.5	72594.9	78864.2	99377.6	95265	124254.1	108715.2	102100	66262.5	72512.6	72521
off-peak kwh	105305.7	102286.5	77705.1	78235.8	87422.4	87235	96445.9	97184.8	102100	73237.5	79187.4	81779
voltage	13200											
previous demand	567	504	477	432	594	756	720	693	621	567	450	585

N5

	jan	feb	march*	april*	may	june	july	aug	sept	oct	nov	dec
bill days	30	30	30	30	30	30	30	30	30	30	30	30
billed kwh	188800	175700	177100	177100	199900	223700	240100	242900	232600	179600	184100	191100
actual demand	549	468	500	500	612	639	666	693	684	585	495	441
billed demand	552	552	552	552	612	639	666	693	684	611	552	552
power factor	90	90	90	90	90	90	90	90	90	90	90	90
on-peak kwh	87414.4	78186.5	85539.3	88904.2	106346.8	116771.4	135176.3	128251.2	116300	85310	87999.8	89817
off-peak kwh	101385.6	97513.5	91560.7	88195.8	93553.2	106928.6	104923.7	114648.8	116300	94290	96100.2	101283
voltage	13200											
previous demand	459	441	500	500	612	675	639	648	610	540	513	504

N6

	jan	feb	march*	april	may	june	july	aug	sept	oct	nov	dec
bill days	30	30	30	30	30	30	30	30	30	30	30	30
billed kwh	264900	278500	280200	288100	328300	331400	361200	360900	352700	295900	286400	264900
actual demand	711	684	765	846	918	936	981	972	981	891	738	711
billed demand	838	838	838	846	918	936	981	972	981	891	785	838
power factor	90	90	90	90	90	90	90	90	90	90	90	90
on-peak kwh	122648.7	123932.5	135336.6	144626.2	174655.6	172990.8	203355.6	190555.2	176350	140552.5	136899.2	124503
off-peak kwh	142251.3	154567.5	144863.4	143473.8	153644.4	158409.2	157844.4	170344.8	176350	155347.5	149500.8	140397
voltage	13200											
previous demand	675	621	644	666	918	972	999	1008	900	855	693	675

N7

	jan	feb	march	april	may	june	july	aug	sept	oct	nov	dec
bill days	30	30	30	30	30	30	30	30	30	30	30	30
billed kwh	1770000	1814000	2078000	1431000	1309000	1655000	1707000	1687000	1651000	1344000	1415000	1857000
actual demand	4056	3957	4674	4641	4530	4713	4875	4890	4893	4356	4023	4152
billed demand	4351	4357	4674	4641	4530	4713	4875	4890	4893	4356	4023	4351
power factor	95	95	95	95	95	95	95	95	95	95	95	95
on-peak kwh	818147	792189	846473	783849	829496	847403	932727	897488	873120	716966	692571	817656
off-peak kwh	951853	1021811	1231527	647151	479504	807597	774273	789512	777880	627034	722429	1039344
voltage	13200											
previous demand	4071	4122	4242	4287	5217	5250	5439	5187	5277	4872	4467	3699

N8

	jan	feb	march	april	may	june	july	aug	sept	oct	nov	dec
bill days	30	30	30	30	30	30	30	30	30	30	30	30
billed kwh	280000	265000	259000	292000	317000	363000	407000	437000	401000	364000	263000	269000
actual demand	751	756	800	907	1195	1212	1432	1418	1444	1171	986	823
billed demand	1023	1023	1023	1023	1195	1212	1432	1418	1444	1171	1156	1156
power factor	90	90	90	90	90	90	90	90	90	90	90	90
on-peak kwh	129640	117925	125097	146584	168644	189486	229141	230736	200500	172900	125714	126430
off-peak kwh	150360	147075	133903	145416	148356	173514	177859	206264	200500	191100	137286	142570
voltage	13200											
previous demand	696	669	646	624	784	1279	1231	1252	1252	1228	1008	700

N9

	jan	feb	march*	april	may	june	july	aug	sept	oct	nov*	dec
bill days	30	30	30	30	31	29	30	30	30	30	30	30
billed kwh	542000	524000	506000	525000	608000	578000	735000	749000	699000	637000	561000	485000
actual demand	1346	1403	1401	1399	2198	2193	2308	2263	2248	2039	1701	1363
billed demand	1804	1804	1804	1804	2198	2193	2308	2263	2248	2039	1846	1804
power factor	95	95	95	95	95	95	95	95	95	95	95	95
on-peak kwh	250946	233180	244398	263550	404591	372714	440963	459331	431231	383185	268158	227950
off-peak kwh	291054	290820	261602	261450	203409	205286	294037	289669	267769	253815	292842	257050
voltage	13200											
previous demand	1408	1391	1414	1420	2106	2255	2152	2121	2107	2099	1763	1427

N10

	jan	feb	march	april	may	june	july*	aug	sept	oct	nov	dec
bill days	30	30	30	30	30	30	30	30	30	30	30	30
billed kwh	1766000	1983000	1897000	2101000	2397000	2278000	2511000	2385000	2690000	2220000	1915000	2003000
actual demand	3774	3633	4242	4677	4842	4938	5113	5289	5232	4599	4080	3663
billed demand	3968	3968	4242	4677	4842	4938	5113	5289	5232	4599	4080	3968
power factor	95	95	95	95	95	95	95	95	95	95	95	95
on-peak kwh	751589	724842	797295	871508	942971	971796	1079730	1015589	1066374	885596	770061	795779
off-peak kwh	1014411	1258158	1099705	1229492	1454029	1306204	1431270	1369411	1623626	1334404	1144939	1207221
voltage	13200											
previous demand	3480	3387	3423	3897	4566	4833	4884	4908	4716	4677	3360	3339

N11

	jan	feb	march	april	may	june	july	aug	sept	oct	nov	dec
bill days	30	30	30	30	30	30	30	30	30	30	29	32
billed kwh	1645000	1316000	1376000	1534000	1534000	1593000	1770000	1625000	1492000	1342000	1356000	1382000
actual demand	3684	3684	3576	4740	4776	5232	5244	5136	4500	4400	4776	3588
billed demand	4282	4282	4282	4740	4776	5232	5244	5136	4500	4400	4776	4282
power factor	95	95	95	95	95	95	95	95	95	95	95	95
on-peak kwh	727986	700542	737460	843354	895704	920646	993162	949050	825090	662736	747000	684300
off-peak kwh	917014	615458	638540	690646	638296	672354	776838	675950	666910	679264	609000	697700
voltage	13200											
previous demand	3458	3504	3552	3444	4416	5352	5196	5160	4740	4764	3492	3492

N12

	jan	feb	march	april	may	june	july	aug	sept	oct	nov	dec
bill days	30	30	30	30	30	30	30	30	30	30	30	30
billed kwh	1128700	1009200	997900	1110300	1161500	1130100	1406300	1321400	1258400	1100600	923700	937500
actual demand	2314	2333	2504	3299	3155	3310	3461	3404	3423	2935	2697	2137
billed demand	2649	2649	2649	3299	3155	3310	3461	3404	3423	2935	2769	2649
power factor	95	95	95	95	95	95	95	95	95	95	95	95
on-peak kwh	515891	431429	507943	542663	617760	585126	705061	718777	588394	556674	431088	421789
off-peak kwh	612809	577771	489957	567637	543750	544974	701239	602623	670006	543926	492612	515711
voltage	13200											
previous demand	2198	2127	2187	2551	2551	3310	3265	2952	3136	2783	2508	2227

HYPOTHETICAL MANUFACTURING CUSTOMERS　　　　RMW__USE DATA WORKSHEETS

M1

	jan	feb	march	april	may	june	july	aug	sept	oct	nov	dec
bill days	30	30	30	30	30	30	30	30	30	30	30	30
billed kwh	3240000	3240000	3240000	3240000	3240000	3240000	3240000	3240000	3240000	3240000	3240000	3240000
actual demand	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000
billed demand	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000
power factor	95	95	95	95	95	95	95	95	95	95	95	95
on-peak kwh	1080000	1080000	1080000	1080000	1080000	1080000	1080000	1080000	1080000	1080000	1080000	1080000
off-peak kwh	2160000	2160000	2160000	2160000	2160000	2160000	2160000	2160000	2160000	2160000	2160000	2160000
voltage	13200											
previous demand	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000

M2

	jan	feb	march	april	may	june	july	aug	sept	oct	nov	dec
bill days	30	30	30	30	30	30	30	30	30	30	30	30
billed kwh	28400000	28400000	28400000	28400000	28400000	28400000	28400000	28400000	28400000	28400000	28400000	28400000
actual demand	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000
billed demand	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000
power factor	95	95	95	95	95	95	95	95	95	95	95	95
on-peak kwh	9457200	9457200	9457200	9457200	9457200	9457200	9457200	9457200	9457200	9457200	9457200	9457200
off-peak kwh	18942800	18942800	18942800	18942800	18942800	18942800	18942800	18942800	18942800	18942800	18942800	18942800
voltage	13200											
previous demand	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000	40000

TOTAL ANNUAL ELECTRIC BILL RMW__WORKSHEET

	BALTIMORE GAS & ELECTRIC	METROPOLITAN EDISON	DELMARVA POWER & LIGHT	PUBLIC SERVICE ELECTRIC & GAS	JERSEY CENTRAL POWER & LIGHT	POTOMAC ELECTRIC POWER CO.	ATLANTIC ELECTRIC
N1	$10,048,478.00	$11,016,106.00	$11,133,222.00	$12,228,310.00	$17,206,368.00	$11,450,754.00	$14,013,511.00
N2	$1,095,037.00	$1,195,441.00	$1,277,008.00	$1,143,043.00	$1,681,626.00	$1,171,652.00	$1,405,951.00
N3	$242,863.10	$227,151.70	$243,396.10	$217,829.30	$317,981.90	$281,375.10	$276,636.60
N4	$159,298.80	$150,856.00	$161,788.30	$142,896.80	$209,031.20	$142,322.00	$186,733.40
N5	$173,704.70	$162,653.80	$171,151.00	$159,203.00	$228,284.10	$170,499.30	$196,767.40
N6	$227,333.20	$244,596.60	$256,484.80	$240,423.50	$345,402.30	$303,111.10	$291,799.20
N7	$1,171,449.00	$1,291,104.00	$1,344,534.00	$1,261,458.00	$1,832,848.00	$1,217,652.00	$1,519,253.00
N8	$300,049.00	$279,113.20	$310,854.80	$259,691.70	$387,744.00	$332,967.70	$347,459.60
N9	$533,301.20	$495,868.30	$541,772.50	$476,092.00	$695,785.30	$535,570.80	$593,377.30
N10	$1,417,079.00	$1,527,912.00	$1,540,720.00	$1,574,193.00	$2,228,110.00	$1,607,615.00	$1,832,205.00
N11	$1,115,676.00	$1,224,075.00	$1,297,767.00	$1,177,302.00	$1,723,950.00	$1,194,448.00	$1,437,754.00
N12	$799,357.30	$866,122.80	$902,366.30	$857,736.00	$1,235,884.00	$901,762.10	$1,012,611.00
TOTAL NON-MANUFACTURING	$17,283,626.30	$18,681,000.40	$19,181,064.80	$19,738,178.30	$28,093,014.80	$19,309,729.10	$23,114,058.50
M1	$1,891,579.00	$2,052,453.00	$1,939,491.00	$2,220,415.00	$3,067,329.00	$2,250,170.00	$2,541,859.00
M2	$16,208,492.00	$17,545,050.00	$16,468,438.00	$19,321,766.00	$26,429,014.00	$18,835,468.00	$21,625,803.00
TOTAL MANUFACTURING	$18,100,071.00	$19,597,503.00	$18,407,929.00	$21,542,181.00	$29,496,343.00	$21,085,638.00	$24,167,662.00
RATIO NON-MNFG./MNFG.	0.9549	0.9532	1.0420	0.9163	0.9524	0.9158	0.9564
TOTAL NON-MANUFACTURING W/O UNIVERSITY OF PENNSYLVANIA (N1)	7235148.3	7664894.4	8047842.8	7509868.3	10886646.8	7858975.1	9100547.5
RATIO NON-MNFG./MNFG. W/O UNIVERSITY OF PENNSYLVANIA (N1)	0.9509	0.9532	1.0419	0.9163	0.9524	0.9158	0.9564

		W/O UNIVERSITY
AVERAGE NON-MNFG. BILL FOR OTHER UTILITIES	$20,238,621.55	$8,213,126.25
PERCENT THAT PECO IS HIGHER	160.77%	167.91%

PENNSYLVANIA ELECTRIC	DUQUESNE LIGHT	PENNSYLVANIA POWER & LIGHT	PECO new rates	PECO-new rates (no ratchet)	PECO old rates	ratchet difference	rate increase
$10,810,643.00	$10,576,070.00	$11,771,491.00	$18,747,700.00	$18,130,820.00	$14,780,743.00	$616,880.00	$3,966,9
$1,198,995.00	$1,321,918.00	$1,230,077.00	$2,212,831.00	$2,141,140.00	$1,648,049.00	$71,691.00	$564,7
$228,164.10	$241,995.70	$237,194.10	$420,865.50	$403,885.80	$312,476.00	$16,979.70	$108,3
$152,117.10	$163,718.20	$157,966.40	$281,610.30	$270,954.60	$207,837.20	$10,655.70	$73,7
$162,847.80	$174,988.80	$171,424.90	$295,453.90	$285,781.80	$221,265.60	$9,672.10	$74,1
$244,343.60	$258,930.60	$256,922.90	$440,767.10	$427,335.70	$331,395.70	$13,431.40	$109,37
$1,288,677.00	$1,333,901.00	$1,340,080.00	$2,293,373.00	$2,270,632.00	$1,735,916.00	$22,741.00	$557,45
$281,973.00	$296,905.00	$288,778.60	$529,924.60	$503,355.60	$388,456.70	$26,569.00	$141,46
$497,405.30	$515,510.00	$509,309.80	$939,146.30	$885,936.80	$695,575.50	$53,209.50	$243,57
$1,506,105.00	$1,652,963.00	$1,624,471.00	$2,581,688.00	$2,560,472.00	$2,021,904.00	$21,216.00	$559,78
$1,226,262.00	$1,341,731.00	$1,257,892.00	$2,250,113.00	$2,184,075.00	$1,679,617.00	$66,038.00	$570,49
$862,189.40	$896,381.40	$905,200.60	$1,544,731.00	$1,509,626.00	$1,173,390.00	$35,105.00	$371,34
$18,459,722.30	$18,775,012.70	$19,750,808.30	$32,538,203.70	$31,574,015.30	$25,196,625.70	$964,188.40	$7,341,57
$1,998,168.00	$2,131,976.00	$2,213,828.00	$3,265,059.00	$3,265,059.00	$2,655,096.00	$0.00	$609,96
$17,001,109.00	$16,990,782.00	$18,912,691.00	$27,423,062.00	$27,423,062.00	$22,552,086.00	$0.00	$4,870,97
$18,999,277.00	$19,122,758.00	$21,126,519.00	$30,688,121.00	$30,688,121.00	$25,207,182.00	$0.00	$5,480,93
0.9716	0.9818	0.9349	1.0603	1.0289	0.9996		
7649079.3	8198942.7	7979317.3	13790503.7	13443195.3			
0.9716	0.9818	0.9349	1.0602	1.0287			

PERCENT DIFFERENCE FROM
NEW PECO RATE

RMW__WORKSHEET

	BGE	METED	DEL	PSEG	JCPL	PEPCO	ATL	PENN	DUQ	PPL	PECO-old
N1	-46.40%	-41.24%	-40.62%	-34.77%	-8.22%	-38.92%	-25.25%	-42.34%	-43.59%	-37.21%	-21.16%
N2	-50.51%	-45.98%	-42.29%	-48.34%	-24.01%	-47.05%	-36.46%	-45.82%	-40.26%	-44.41%	-25.52%
N3	-42.29%	-46.03%	-42.17%	-48.24%	-24.45%	-33.14%	-34.27%	-45.79%	-42.50%	-43.64%	-25.75%
N4	-43.43%	-46.43%	-42.55%	-49.26%	-25.77%	-49.46%	-33.69%	-45.98%	-41.86%	-43.91%	-26.20%
N5	-41.21%	-44.95%	-42.07%	-46.12%	-22.73%	-42.29%	-33.40%	-44.88%	-40.77%	-41.98%	-25.11%
N6	-48.42%	-44.51%	-41.81%	-45.45%	-21.64%	-31.23%	-33.80%	-44.56%	-41.25%	-41.71%	-24.81%
N7	-48.92%	-43.70%	-41.37%	-45.00%	-20.08%	-46.91%	-33.75%	-43.81%	-41.84%	-41.57%	-24.31%
N8	-43.38%	-47.33%	-41.34%	-50.99%	-26.83%	-37.17%	-34.43%	-46.79%	-43.97%	-45.51%	-26.70%
N9	-43.21%	-47.20%	-42.31%	-49.31%	-25.91%	-42.97%	-36.82%	-47.04%	-45.11%	-45.77%	-25.94%
N10	-45.11%	-40.82%	-40.32%	-39.02%	-13.70%	-37.73%	-29.03%	-41.66%	-35.97%	-37.08%	-21.68%
N11	-50.42%	-45.60%	-42.32%	-47.68%	-23.38%	-46.92%	-36.10%	-45.50%	-40.37%	-44.10%	-25.35%
N12	-48.25%	-43.93%	-41.58%	-44.47%	-19.99%	-41.62%	-34.45%	-44.19%	-41.97%	-41.40%	-24.04%
TOTAL NON-MANUFACTURING	-46.88%	-42.59%	-41.05%	-39.34%	-13.66%	-40.66%	-28.96%	-43.27%	-42.30%	-39.30%	-22.56%
M1	-42.07%	-37.14%	-40.60%	-31.99%	-6.06%	-31.08%	-22.15%	-38.80%	-34.70%	-32.20%	-18.68%
M2	-40.89%	-36.02%	-39.95%	-29.54%	-3.62%	-31.32%	-21.14%	-38.00%	-38.04%	-31.03%	-17.76%
TOTAL MANUFACTURING	-41.02%	-36.14%	-40.02%	-29.80%	-3.88%	-31.29%	-21.25%	-38.09%	-37.69%	-31.16%	-17.86%

PERCENT DIFFERENCE FROM
OLD PECO RATE

RMW_WORKSHEET

	BGE	METED	DEL	PSEG	JCPL	PEPCO	ATL	PENN	DUQ	PPL	PECO-new	PECO-new no ratchet	rate increa due to ratc
N1	-32.02%	-25.47%	-24.68%	-17.27%	16.41%	-22.53%	-5.19%	-26.86%	-28.45%	-20.36%	26.84%	22.67%	3.29%
N2	-33.56%	-27.46%	-22.51%	-30.64%	2.04%	-29.91%	-14.69%	-27.25%	-19.79%	-25.36%	34.27%	29.92%	3.24%
N3	-22.28%	-27.31%	-22.11%	-30.29%	1.76%	-9.95%	-11.47%	-26.98%	-22.56%	-24.09%	34.69%	29.25%	4.03%
N4	-23.35%	-27.42%	-22.16%	-31.25%	0.57%	-31.52%	-10.15%	-26.81%	-21.23%	-24.00%	35.50%	30.37%	3.78%
N5	-21.49%	-26.49%	-22.65%	-28.05%	3.17%	-22.94%	-11.07%	-26.40%	-20.91%	-22.53%	33.53%	29.16%	3.27%
N6	-31.40%	-26.19%	-22.60%	-27.45%	4.23%	-8.53%	-11.95%	-26.27%	-21.87%	-22.47%	33.00%	28.95%	3.05%
N7	-32.52%	-25.62%	-22.55%	-27.33%	5.58%	-29.86%	-12.48%	-25.76%	-23.16%	-22.80%	32.11%	30.80%	0.99%
N8	-22.76%	-28.15%	-19.98%	-33.15%	-0.18%	-14.28%	-10.55%	-27.41%	-23.57%	-25.66%	36.42%	29.58%	5.01%
N9	-23.33%	-28.71%	-22.11%	-31.55%	0.03%	-23.00%	-14.69%	-28.49%	-25.89%	-26.78%	35.02%	27.37%	5.67%
N10	-29.91%	-24.43%	-23.80%	-22.14%	10.20%	-20.49%	-9.38%	-25.51%	-18.25%	-19.66%	27.69%	26.64%	0.82%
N11	-33.58%	-27.12%	-22.73%	-29.91%	2.64%	-28.89%	-14.40%	-26.99%	-20.12%	-25.11%	33.97%	30.03%	2.93%
N12	-31.98%	-26.19%	-23.10%	-26.90%	5.33%	-23.15%	-13.70%	-26.52%	-23.61%	-22.86%	31.65%	28.66%	2.27%
TOTAL NON-MANUFACTURING	-31.40%	-25.86%	-23.87%	-21.66%	11.50%	-23.36%	-8.27%	-26.74%	-25.49%	-21.61%	29.14%	25.31%	2.96%
M1	-28.76%	-22.70%	-26.95%	-16.37%	15.53%	-15.25%	-4.26%	-24.74%	-19.70%	-16.62%	22.97%	22.97%	0.00%
M2	-28.13%	-22.20%	-26.98%	-14.32%	17.19%	-16.48%	-4.11%	-24.61%	-24.66%	-16.14%	21.60%	21.60%	0.00%
TOTAL MANUFACTURING	-28.19%	-22.25%	-26.97%	-14.54%	17.02%	-16.35%	-4.12%	-24.63%	-24.14%	-16.19%	21.74%	21.74%	0.00%

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Public Utility Commission

ERRATA
FOR THE TESTIMONY OF
ROBERT M WIRTSHAFTER

1. RMW p. 3, lines 13, 14: "An increase of one kilowatt of demand during the summer months by a customer adds $24.00 to a non-manufacturing customer's annual bill..." should read "An increase of one kilowatt of demand during a summer month by a customer adds $24.00 to a manufacturing customer's annual bill..."

2. RMW p. 3, line 22: "...the ratchet is used by only two other utilities in the region..." should read "...the ratchet is used by only two other utilities in PJM..."

3. RMW p. 9, line 24: "Column 4" should read "Column 5".

4. RMW p. 12, 8-11: "The combined result is that PECo has the highest demand-related charges of any utility in PJM. PECo's proposed demand charges are so out of line that they will be 426 percent higher than Delmarva Power and Light, the next highest in the area." should read "The combined result is that PECo has the highest demand signal of any utility in PJM. PECo's proposed demand charges at the margin are so out of line that they will be 426 percent higher for the University of Pennsylvania than they would be with Delmarva Power and Light, the next highest in PJM."

5. RMW p. 19, line 22: "Of the eleven other utilities that I examined, only two, Metropolitan Edison and Delmarva have demand ratchets." should read "Of the eleven other utilities that I examined, only three, Duquesne Light, Metropolitan Edison, and Delmarva, have demand ratchets."

6. RMW p. 20, line 1: Add additional sentences at end of previous paragraph: "Duquesne's demand ratchet affects only those customers with demand exceeding 5000 kw. Of the UUC customers analyzed, only the University of Pennsylvania would be affected with a net increase of $8275.00 due to Duquesne's demand ratchet, or 1.34% of PECo's charge due to the demand ratchet."

7. RMW__13 should be replaced by Attachment RMW__13 (Revised).

8. RMW__14 should be replaced by Attachment RMW__14 (Revised).

9. RMW__WORKSHEET should be replaced by Attachment RMW__WORKSHEET (Revised). For Duquesne Light the following changes are made: the bill for the University of Pennsylvania is changed from $10,576,070.00 to $10,584,345.00. The Non-manufacturing total is changed from $18,775,012.70 to $18,783,287.70. The ratio of non-manufacturing/manufacturing bills is changed from .9818 to .9822. The percent difference from the new PECO rate for Duquesne Light is changed from -43.59%

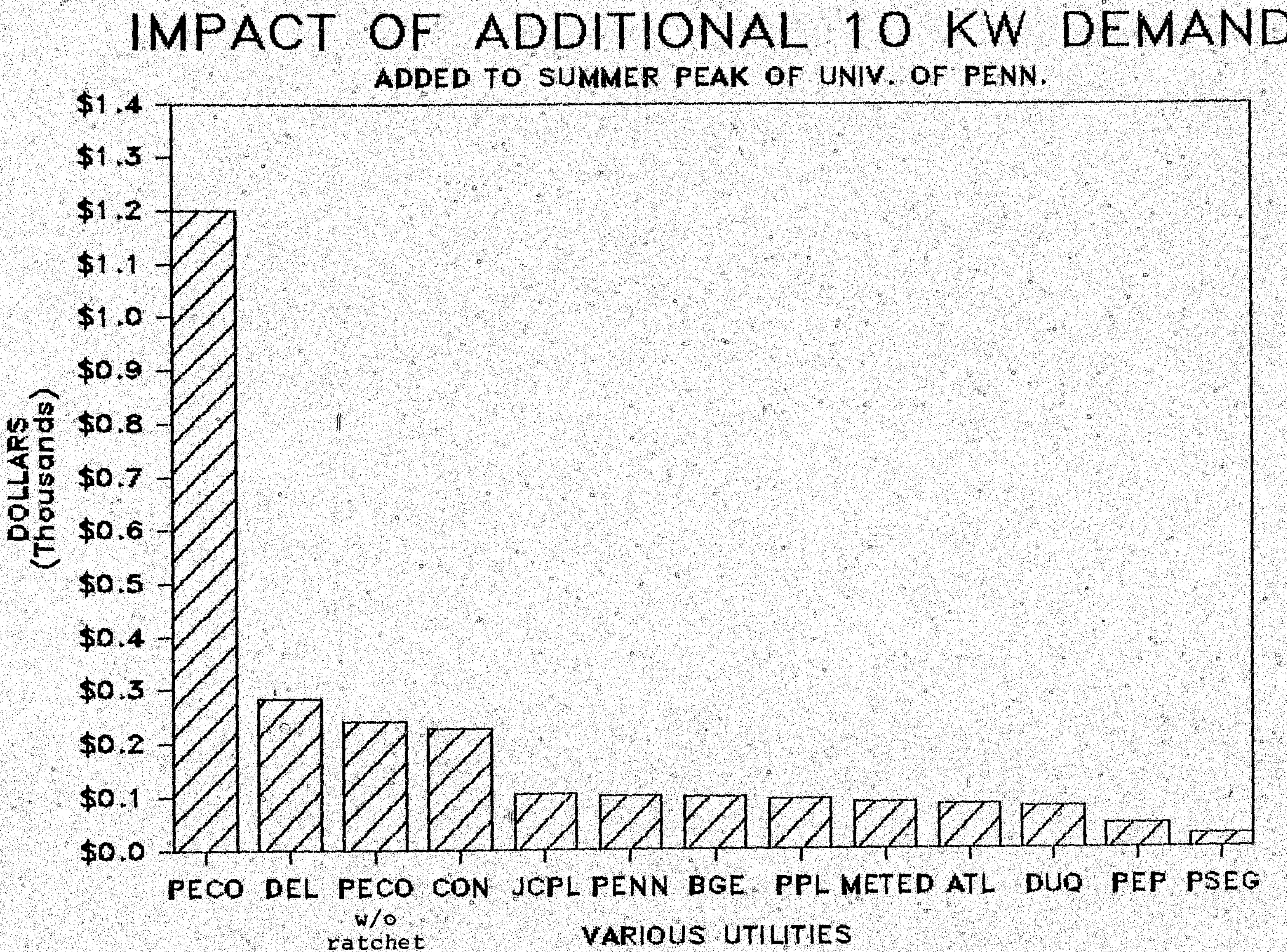
to -43.54%. The total non-manufacturing percent difference from the new PECO rate is changed from -42.30% to -42.27%. The percent difference from the old PECO rate for Duquesne Light is changed from -28.45% to -28.39%. The total non-manufacturing percent difference from the old PECO rate is changed from -25.49% to -25.45%. The average non-manufacturing bill for other utilities is changed from $20,238,621.55 to $20,239.449.05.

Attachment RMW__13 (Revised)

IMPACT OF 10 KW INCREASE IN DEMAND IN PEAK SUMMER MONTH
FOR UNIVERSITY OF PENNSYLVANIA

impact of 10 kw demand increase	utility	without demand increase	with 10 kw demand increase
$1,200	PECO	$18,747,700	$18,748,900
$282	DEL	$11,133,222	$11,133,504
$240	PECO**	$18,130,820	$18,131,060
$227	CON	$19,570,789	$19,571,016
$103	JCPL	$17,206,368	$17,206,471
$101	PENN	$10,810,643	$10,810,744
$98	BGE	$10,048,478	$10,048,576
$92	PPL	$11,771,491	$11,771,583
$87	METED	$11,016,106	$11,016,193
$82	ATL	$14,013,511	$14,013,593
$76	DUQ	$10,584,345	$10,584,421
$44	PEP	$11,450,754	$11,450,798
$24	PSEG	$12,228,310	$12,228,334

**PECO without ratchet



Source: Utility rate schedule analysis & Univ. of PA electric bills.

Attachment RMW__14 (Revised)

TOTAL ANNUAL ELECTRIC BILL

Attachment RMW__WORKSHEET (Revised)

	BALTIMORE GAS & ELECTRIC	METROPOLITAN EDISON	DELMARVA POWER & LIGHT	PUBLIC SERVICE ELECTRIC & GAS	JERSEY CENTRAL POWER & LIGHT	POTOMAC ELECTRIC POWER CO.	ATLANTIC ELECTRIC
N1	$10,048,478.00	$11,016,106.00	$11,133,222.00	$12,228,310.00	$17,206,368.00	$11,450,754.00	$14,013,511.0
N2	$1,095,037.00	$1,195,441.00	$1,277,008.00	$1,143,043.00	$1,681,626.00	$1,171,652.00	$1,405,951.0
N3	$242,863.10	$227,151.70	$243,396.10	$217,829.30	$317,981.90	$281,375.10	$276,636.6
N4	$159,298.80	$150,856.00	$161,788.30	$142,896.80	$209,031.20	$142,322.00	$186,733.4
N5	$173,704.70	$162,653.80	$171,151.00	$159,203.00	$228,284.10	$170,499.30	$196,767.4
N6	$227,333.20	$244,596.60	$256,484.80	$240,423.50	$345,402.30	$303,111.10	$291,799.2
N7	$1,171,449.00	$1,291,104.00	$1,344,534.00	$1,261,458.00	$1,832,848.00	$1,217,652.00	$1,519,253.0
N8	$300,049.00	$279,113.20	$310,854.80	$259,691.70	$387,744.00	$332,967.70	$347,459.6
N9	$533,301.20	$495,868.30	$541,772.50	$476,092.00	$695,785.30	$535,570.80	$593,377.3
N10	$1,417,079.00	$1,527,912.00	$1,540,720.00	$1,574,193.00	$2,228,110.00	$1,607,615.00	$1,832,205.0
N11	$1,115,676.00	$1,224,075.00	$1,297,767.00	$1,177,302.00	$1,723,950.00	$1,194,448.00	$1,437,754.00
N12	$799,357.30	$866,122.80	$902,366.30	$857,736.00	$1,235,884.00	$901,762.10	$1,012,611.00
TOTAL NON-MANUFACTURING	$17,283,626.30	$18,681,000.40	$19,181,064.80	$19,738,178.30	$28,093,014.80	$19,309,729.10	$23,114,058.50
M1	$1,891,579.00	$2,052,453.00	$1,939,491.00	$2,220,415.00	$3,067,329.00	$2,250,170.00	$2,541,859.00
M2	$16,208,492.00	$17,545,050.00	$16,468,438.00	$19,321,766.00	$26,429,014.00	$18,835,468.00	$21,625,803.00
TOTAL MANUFACTURING	$18,100,071.00	$19,597,503.00	$18,407,929.00	$21,542,181.00	$29,496,343.00	$21,085,638.00	$24,167,662.00
RATIO NON-MNFG./MNFG.	0.9549	0.9532	1.0420	0.9163	0.9524	0.9158	0.9564
TOTAL NON-MANUFACTURING W/O UNIVERSITY OF PENNSYLVANIA (N1)	7235148.3	7664894.4	8047842.8	7509868.3	10886646.8	7858975.1	9100547.5
RATIO NON-MNFG./MNFG. W/O UNIVERSITY OF PENNSYLVANIA (N1)	0.9509	0.9532	1.0419	0.9163	0.9524	0.9158	0.9564

		W/O UNIVERSITY
AVERAGE NON-MNFG. BILL FOR OTHER UTILITIES	$20,239,449.05	$8,213,126.25
PERCENT THAT PECO IS HIGHER	160.77%	167.91%

PENNSYLVANIA ELECTRIC	DUQUESNE LIGHT	PENNSYLVANIA POWER & LIGHT	PECO new rates	PECO-new rates (no ratchet)	PECO old rates	ratchet difference	rate incr
$10,810,643.00	$10,584,345.00	$11,771,491.00	$18,747,700.00	$18,130,820.00	$14,780,743.00	$616,880.00	$3,966,957.
$1,198,995.00	$1,321,918.00	$1,230,077.00	$2,212,831.00	$2,141,140.00	$1,648,049.00	$71,691.00	$564,782.
$228,164.10	$241,995.70	$237,194.10	$420,865.50	$403,885.80	$312,476.00	$16,979.70	$108,389.
$152,117.10	$163,718.20	$157,966.40	$281,610.30	$270,954.60	$207,837.20	$10,655.70	$73,773.
$162,847.80	$174,988.80	$171,424.90	$295,453.90	$285,781.80	$221,265.60	$9,672.10	$74,188.
$244,343.60	$258,930.60	$256,922.90	$440,767.10	$427,335.70	$331,395.70	$13,431.40	$109,371.
$1,288,677.00	$1,333,901.00	$1,340,080.00	$2,293,373.00	$2,270,632.00	$1,735,916.00	$22,741.00	$557,457.
$281,973.00	$296,905.00	$288,778.60	$529,924.60	$503,355.60	$388,456.70	$26,569.00	$141,467.
$497,405.30	$515,510.00	$509,309.80	$939,146.30	$885,936.80	$695,575.50	$53,209.50	$243,570.
$1,506,105.00	$1,652,963.00	$1,624,471.00	$2,581,688.00	$2,560,472.00	$2,021,904.00	$21,216.00	$559,784.
$1,226,262.00	$1,341,731.00	$1,257,892.00	$2,250,113.00	$2,184,075.00	$1,679,617.00	$66,038.00	$570,496.
$862,189.40	$896,381.40	$905,200.60	$1,544,731.00	$1,509,626.00	$1,173,390.00	$35,105.00	$371,341.
$18,459,722.30	$18,783,287.70	$19,750,808.30	$32,538,203.70	$31,574,015.30	$25,196,625.70	$964,188.40	$7,341,578.
$1,998,168.00	$2,131,976.00	$2,213,828.00	$3,265,059.00	$3,265,059.00	$2,655,096.00	$0.00	$609,963.
$17,001,109.00	$16,990,782.00	$18,912,691.00	$27,423,062.00	$27,423,062.00	$22,552,086.00	$0.00	$4,870,976.
$18,999,277.00	$19,122,758.00	$21,126,519.00	$30,688,121.00	$30,688,121.00	$25,207,182.00	$0.00	$5,480,939.
0.9716	0.9822	0.9349	1.0603	1.0289	0.9996		
7649079.3	8198942.7	7979317.3	13790503.7	13443195.3			
0.9716	0.9818	0.9349	1.0602	1.0287			

PERCENT DIFFERENCE FROM
NEW PECO RATE

Attachment RMW_WORKSHEET (Revised)

	BGE	METED	DEL	PSEG	JCPL	PEPCO	ATL	PENN	DUQ	PPL	PECO-old
N1	-46.40%	-41.24%	-40.62%	-34.77%	-8.22%	-38.92%	-25.25%	-42.34%	-43.54%	-37.21%	-21.16%
N2	-50.51%	-45.98%	-42.29%	-48.34%	-24.01%	-47.05%	-36.46%	-45.82%	-40.26%	-44.41%	-25.52%
N3	-42.29%	-46.03%	-42.17%	-48.24%	-24.45%	-33.14%	-34.27%	-45.79%	-42.50%	-43.64%	-25.75%
N4	-43.43%	-46.43%	-42.55%	-49.26%	-25.77%	-49.46%	-33.69%	-45.98%	-41.86%	-43.91%	-26.20%
N5	-41.21%	-44.95%	-42.07%	-46.12%	-22.73%	-42.29%	-33.40%	-44.88%	-40.77%	-41.98%	-25.11%
N6	-48.42%	-44.51%	-41.81%	-45.45%	-21.64%	-31.23%	-33.80%	-44.56%	-41.25%	-41.71%	-24.81%
N7	-48.92%	-43.70%	-41.37%	-45.00%	-20.08%	-46.91%	-33.75%	-43.81%	-41.84%	-41.57%	-24.31%
N8	-43.38%	-47.33%	-41.34%	-50.99%	-26.83%	-37.17%	-34.43%	-46.79%	-43.97%	-45.51%	-26.70%
N9	-43.21%	-47.20%	-42.31%	-49.31%	-25.91%	-42.97%	-36.82%	-47.04%	-45.11%	-45.77%	-25.94%
N10	-45.11%	-40.82%	-40.32%	-39.02%	-13.70%	-37.73%	-29.03%	-41.66%	-35.97%	-37.08%	-21.68%
N11	-50.42%	-45.60%	-42.32%	-47.68%	-23.38%	-46.92%	-36.10%	-45.50%	-40.37%	-44.10%	-25.35%
N12	-48.25%	-43.93%	-41.58%	-44.47%	-19.99%	-41.62%	-34.45%	-44.19%	-41.97%	-41.40%	-24.04%
TOTAL NON-MANUFACTURING	-46.88%	-42.59%	-41.05%	-39.34%	-13.66%	-40.66%	-28.96%	-43.27%	-42.27%	-39.30%	-22.56%
M1	-42.07%	-37.14%	-40.60%	-31.99%	-6.06%	-31.08%	-22.15%	-38.80%	-34.70%	-32.20%	-18.68%
M2	-40.89%	-36.02%	-39.95%	-29.54%	-3.62%	-31.32%	-21.14%	-38.00%	-38.04%	-31.03%	-17.76%
TOTAL MANUFACTURING	-41.02%	-36.14%	-40.02%	-29.80%	-3.88%	-31.29%	-21.25%	-38.09%	-37.69%	-31.16%	-17.86%

PERCENT DIFFERENCE FROM
OLD PECO RATE

Attachment RMW_WORKSHEET (Revised)

	BGE	METED	DEL	PSEG	JCPL	PEPCO	ATL	PENN	DUQ	PPL	PECO-new	PECO-new no ratchet	rate increase due to ratchet
N1	-32.02%	-25.47%	-24.68%	-17.27%	16.41%	-22.53%	-5.19%	-26.86%	-28.39%	-20.36%	26.84%	22.67%	3.29%
N2	-33.56%	-27.46%	-22.51%	-30.64%	2.04%	-28.91%	-14.69%	-27.25%	-19.79%	-25.36%	34.27%	29.92%	3.24%
N3	-22.28%	-27.31%	-22.11%	-30.29%	1.76%	-9.95%	-11.47%	-26.98%	-22.56%	-24.09%	34.69%	29.25%	4.03%
N4	-23.35%	-27.42%	-22.16%	-31.25%	0.57%	-31.52%	-10.15%	-26.81%	-21.23%	-24.00%	35.50%	30.37%	3.78%
N5	-21.49%	-26.49%	-22.65%	-28.05%	3.17%	-22.94%	-11.07%	-26.40%	-20.91%	-22.53%	33.53%	29.16%	3.27%
N6	-31.40%	-26.19%	-22.60%	-27.45%	4.23%	-8.53%	-11.95%	-26.27%	-21.87%	-22.47%	33.00%	28.95%	3.05%
N7	-32.52%	-25.62%	-22.55%	-27.33%	5.58%	-29.86%	-12.48%	-25.76%	-23.16%	-22.80%	32.11%	30.80%	0.99%
N8	-22.76%	-28.15%	-19.98%	-33.15%	-0.18%	-14.28%	-10.55%	-27.41%	-23.57%	-25.66%	36.42%	29.58%	5.01%
N9	-23.33%	-28.71%	-22.11%	-31.55%	0.03%	-23.00%	-14.69%	-28.49%	-25.89%	-26.78%	35.02%	27.37%	5.67%
N10	-29.91%	-24.43%	-23.80%	-22.14%	10.20%	-20.49%	-9.38%	-25.51%	-18.25%	-19.66%	27.69%	26.64%	0.82%
N11	-33.58%	-27.12%	-22.73%	-29.91%	2.64%	-28.89%	-14.40%	-26.99%	-20.12%	-25.11%	33.97%	30.03%	2.93%
N12	-31.88%	-26.19%	-23.10%	-26.90%	5.33%	-23.15%	-13.70%	-26.52%	-23.61%	-22.86%	31.65%	28.66%	2.27%
TOTAL NON-MANUFACTURING	-31.40%	-25.86%	-23.87%	-21.66%	11.50%	-23.36%	-8.27%	-26.74%	-25.45%	-21.61%	29.14%	25.31%	2.96%
M1	-28.76%	-22.70%	-26.95%	-16.37%	15.53%	-15.25%	-4.26%	-24.74%	-19.70%	-16.62%	22.97%	22.97%	0.00%
M2	-28.13%	-22.20%	-26.98%	-14.32%	17.19%	-16.48%	-4.11%	-24.61%	-24.66%	-16.14%	21.60%	21.60%	0.00%
TOTAL MANUFACTURING	-28.19%	-22.25%	-26.97%	-14.54%	17.02%	-16.35%	-4.12%	-24.63%	-24.14%	-16.19%	21.74%	21.74%	0.00%