R-973953

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

**APPLICATION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS RESTRUCTURING PLAN
UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE**

Exhibit 2

DOCKETED
NOV 04 1997

**RESPONSE TO FILING REQUIREMENTS
RESPONSES G-6 THROUGH G-8**

PROTHONOTARY'S OFFICE
97 OCT 20 AM 9:39

DOCUMENT FOLDER
DOCUMENT FOLDER

Vol 41

PECO Energy Company
Response to Filing Requirements

Schedule G-6
Respondent: Gregory A. Cucchi

Q: Provide a description of the property of the utility and an explanation of the system's operation. Supply the following, using available projections, if actual data is unavailable:

(a) A schedule of generating capability during the base year, net dependable capacity in kilowatts by unit, plant capacity factor by unit, and total fuel consumption by type and cost for each unit, if available, or for each station, and operation and maintenance expenses by station.
(b) A schedule showing for the base year and for the 12-month period immediately preceding the base year the scheduled and unscheduled outages -- in excess of 48 hours -- for each station, the equipment or unit involved, the date the outage occurred, duration of the outage, maintenance expenses incurred for each outage, if available, and amounts reimbursable from suppliers or insurance companies.
(c) A schedule for each unit retired during the base year or subsequent to the end of the base year which shows the unit's kilowatt capacity, hours of operation during the base year, net output generated, cents/kilowatt hour of maintenance and fuel expenses, and date of retirement.
(d) A schedule showing the latest projections of capacity additions and retirements -- costs and kilowatts -- and reserve capacity at the time of peak for at least ten years beyond the base year, including the in-service dates -- actual or expected.

Response:

(a) Attachment G-7 is the Company's May, 1996 Annual Resource Planning Report (ARPR) which contains a schedule of the company's generating capability during the base year, and the net dependable capacity by unit. The only update to the ARPR for future years is that the capacity of Limerick 1 has been uprated from 1055 MW to 1105 MW. The 1996 Capacity factors for each unit are provided in response to schedule L-9. Attachments G-6a and G-6b are ECA No. 6 Quarterly Report No. 4 and ECA No. 7 Quarterly Report No. 3 respectively which contain the fuel

consumption by type and cost for each unit for each month of 1996. The O&M expense by station is contained in the Company's FERC Form, provided as Attachment G-6.

(b) Attachment G-6c is an excerpt from the Company's ECA No. 7 filing which provides a summary of actual outages from January 1995 through February 1996 and projected outages for the remainder of 1996 and 1997.

(c) No units were retired during the base year.

(d) Attachment G-7 is the Company's May 1996 ARPR which contains a complete evaluation of the Company's resources and loads. Additionally the Direct Testimony of Gregory A. Cucchi discusses the Company's capacity position and reserve requirements.

THIS FILING IS (CHECK ONE BOX FOR EACH ITEM)		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____
Item 2: ☐ An Original Signed Form	OR ☒	Conformed Copy

Attachment G-6

Form Approved
OMB No. 1902-0021
(Expires 7/31/98)

FERC Form No. 1: ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHERS

This report is mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year of Report
PECO Energy Company	Dec. 31, 1996

Coopers
&Lybrand

Coopers & Lybrand L.L.P.

a professional services firm

REPORT OF INDEPENDENT ACCOUNTANTS

We have audited the balance sheets of PECO Energy Company as of December 31, 1996 and 1995, and the related statements of income for the years then ended, and the statements of retained earnings and cash flows for the year ended December 31, 1996, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form No. 1. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than generally accepted accounting principles.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of PECO Energy Company as of December 31, 1996 and 1995, the results of its operations and its cash flows for the year ended December 31, 1996 and net income for the year ended December 31, 1995, in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

This report is intended solely for the information and use of the board of directors and management of PECO Energy Company and the Federal Energy Regulatory Commission.

Coopers & Lybrand LLP

2400 Eleven Penn Center
Philadelphia, Pennsylvania
February 3, 1997

Coopers & Lybrand L.L.P. is a member of Coopers & Lybrand International, a limited liability association incorporated in Switzerland.

INSTRUCTIONS FOR FILING THE

FERC FORM NO. 1

GENERAL INFORMATION

I. Purpose

This form is a regulatory support requirement (18 CFR 141.1). It is designed to collect financial and operational information from major electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. This report is also secondarily considered to be a nonconfidential public use form supporting a statistical publication (Financial Statistics of Selected Electric Utilities), published by the Energy Information Administration.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 CFR 101), must submit this form.

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) One million megawatt hours of total annual sales,

(2) 100 megawatt hours of annual sales for resale,

(3) 500 megawatt hours of annual power exchanges delivered, or

(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit this form on electronic media consisting of two (2) duplicate data diskettes and an original and six (6) conformed paper copies, properly filed in and attested, to:

Office of the Secretary
Federal Energy Regulatory Commission
888 First Street, NE.
Room 1A-21
Washington, DC 20426

Retain one copy of this report for your files.

Include with the original and each conformed paper copy of this form the subscription statement required by 18 C.F.R. 385.2011(c)(5). Paragraph (c)(5) of 18 C.F.R. 385.2011 requires each respondent submitting data electronically to file a subscription stating that the paper copies contain the same information as contained on the electronic media, that the signer knows the contents of the paper copies and electronic media, and that the contents as stated in the copies and on the electronic media are true to the best knowledge and belief of the signer.

(b) Submit immediately upon publication, four (4) copies of the latest annual report to stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. (Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Page 4, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared.) Mail these reports to:

Chief Accountant
Federal Energy Regulatory Commission
888 First Street, NE.
Room 1A-21
Washington, DC 20426

(c) For the CPA certification, submit with the original submission, or within 30 days after the filing date for this form, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984):

(i) Attesting to the conformity, in all material aspects, of the below listed (schedules and) pages with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

(ii) Signed by independent certified public accountants or an independent licensed public accountant, certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 CFR 41.10-41.12 for specific qualifications.)

III. *What and Where to Submit (Continued)*

(c) Continued

Schedules	*Reference* Pages
Comparative Balance Sheet	110 - 113
Statement of Income	114 - 117
Statement of Retained Earnings	118 - 119
Statement of Cash Flows	120 - 121
Notes to Financial Statements	122 - 123

When accompanying this form, insert the letter or report immediately following the cover sheet. When submitting after the filing date for this form, send the letter or report to the Office of the Secretary at the address indicated at III (a).

Use the following form for the letter or report unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

In connection with our regular examination of the financial statements of for the year ended on which we have reported separately under date of we have also reviewed schedules of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding *paragraph (except as noted below) conform in all material* respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

State in the letter or report, which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(d) Federal, State and Local Governments and other authorized users may obtain additional blank copies to meet their requirements free of charge from:

Public Reference and Files Maintenance Branch
Federal Energy Regulatory Commission
888 First Street, NE.
Room 2A-1 ED-12.2
Washington, DC 20426
(202) 208-2474

IV. *When to Submit:*

Submit this report form on or before April 30th of the year following the year covered by this report.

V. *Where to Send Comments on Public Reporting Burden.*

The public reporting burden for this collection of information is estimated to average 1,217 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any aspect of this collection of information, including suggestions for reducing this burden, to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 (Attention: Mr. Michael Miller, ED-12.3); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR 101) (U.S. of A.). Interpret all accounting words and phrases in accordance with the U. S. of A.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting year, and use for statement of income accounts the current year's amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous annual report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2, 3, and 4.

V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below). The date of the resubmission must be reported in the header for all form pages, whether or not they are changed from the previous filing.

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses. ( ).

VII. For any resubmissions, two (2) new data diskettes and an original and six (6) conformed paper copies of the entire form, as well as the appropriate number of copies of the subscription statement indicated at instruction III (a) must be filed. Resubmissions must be numbered sequentially both on the diskettes and on the cover page of the paper copies of the form. In addition, the cover page of each paper copy must indicate that the filing is a resubmission. Send the resubmissions to the address indicated at instruction III (a).

VIII. Do not make references to reports of previous years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous year, the figures reported must be based upon those shown by the annual report of the previous year, or an appropriate explanation given as to why the different figures were used.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. 791a-825r)

"Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to wit:
...(3) `corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include `municipalities' as hereinafter defined;

(4) `person' means an individual or a corporation;

(5) `licensee' means any person, State, or municipality licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) `municipality' means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the laws thereof to carry on the business of developing, transmitting, utilizing, or distributing power;...."

(11) `project' means a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or forebay reservoirs directly connected therewith, the primary line or lines transmitting power therefrom to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, lands, or interest in lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered -

(a) To make investigations and to collect and record data concerning the utilization of the water resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites,...to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every licensee and every public utility shall file with the Commission such annual and other periodic or special reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and form in which such reports shall be made, amd require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies."

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the form or forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be filed...."

GENERAL PENALTIES

"Sec. 315. (a) Any licensee or public utility which willfully fails, within the time prescribed by the Commission, to comply with any order of the Commission, to file any report required under this Act or any rule or regulation of the Commission thereunder, to submit any information of document required by the Commission in the course of an investigation conducted under this Act,...shall forfeit to the United States an amount not exceeding $1,000 to be fixed by the Commission after notice and opportunity for hearing...."

FERC FORM NO. 1:

ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES LICENSEES AND OTHER

IDENTIFICATION		
01 Exact legal Name of Respondent PECO Energy Company		02 Year of Report Dec. 31, 1996
03 Previous Name and Date of Change (if name changed during year)		
04 Address of Principal Office at End of Year (Street, City, State, Zip Code) 2301 Market Street, Philadelphia, PA 19101		
05 Name of Contact Person Susan A. Wade		06 Title of Contact Person Manager - External Reporting
07 Address of Contact Person (Street, City, State, Zip Code) 2301 Market Street, Philadelphia, PA 19101		
08 Telephone of Contact Person, including Area Code (215) 841-5696	09 This Report is (1) x An Original (2) A Resubmission	10 Date of Report (Mo, Da, Yr) 12/31/96

ATTESTATION

The undersigned officer certifies that he/she has examined the accompanying report, that to the best of his / her knowledge information and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from and including January 1 to and including December 31 of the year of the report.

01 Name	03 Signature	04 Date Signed (Mo, Da, Yr)
Thomas P. Hill, Jr.		
02 Title Vice President and Controller		03/31/97

Title 18, U.S.C. 1001, makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

LIST OF SCHEDULES (Electric Utility)

Enter in column (d) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
GENERAL CORPORATE INFORMATION AND FINANCIAL STATEMENTS			
General Information	101	Ed. 12-87	
Control Over Respondent	102	Ed. 12-96	none
Corporations Controlled by Respondent	103	Ed. 12-96	
Officers	104	Ed. 12-96	
Directors	105	Ed. 12-95	
Security Holders and Voting Powers	106 - 107	Ed. 12-96	
Important Changes During the Year	108 - 109	Ed. 12-96	
Comparative Balance Sheet	110 - 113	Ed. 12-94	
Statement of Income for the Year	114 - 117	Ed. 12-96	
Statement of Retained Earnings for the Year	118 - 119	Ed. 12-96	
Statement of Cash Flows	120 - 121	Ed. 12-96	
Notes to Financial Statements	122 - 123	Ed. 12-96	
BALANCE SHEET SUPPORTING SCHEDULES (Assets and Other Debits)			
Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization, and Depletion	200 - 201	Ed. 12-89	
Nuclear Fuel Materials	202 - 203	Ed. 12-89	
Electric Plant in Service	204 - 207	Rev. 12-95	
Electric Plant Leased to Others	213	Rev. 12-95	none
Electric Plant Held for Future Use	214	Ed. 12-89	
Construction Work in Progress -- Electric	216	Ed. 12-87	
Construction Overheads -- Electric	217	Ed. 12-89	
General Description of Construction Overhead Procedure	218	Ed. 12-88	
Accumulated Provision for Depreciation of Electric Utility Plant.	219	Ed. 12-88	
Nonutility Property	221	Rev. 12-95	
Investment in Subsidiary Companies	224 - 225	Ed. 12-89	
Materials and Supplies	227	Ed. 12-96	
Allowances	228 - 229	Ed. 12-95	
Extraordinary Property Losses	230	Ed. 12-93	
Unrecovered Plant and Regulatory Study Costs	230	Ed. 12-93	
Other Regulatory Assets	232	Ed. 12-95	
Miscellaneous Deferred Debits	233	Ed. 12-94	
Accumulated Deferred Income Taxes (Account 190)	234	Ed. 12-88	
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits)			
Capital Stock	250 - 251	Ed. 12-91	
Capital Stock Subscribed, Capital Stock Liability for Conversion, Premium on Capital Stock, and Installments Received on Capital Stock	252	Rev. 12-95	
Other Paid-in Capital	253	Ed. 12-87	
Discount on Capital Stock	254	Ed. 12-87	none
Capital Stock Expense	254	Ed. 12-86	none
Long-Term Debt	256 - 257	Ed. 12-96	

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits) (Continued)			
Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes	261	Ed. 12-96	
Taxes Accrued, Prepaid and Charged During Year	262 - 263	Ed. 12-96	
Accumulated Deferred Investment Tax Credits	266 - 267	Ed. 12-89	
Other Deferred Credits	269	Ed. 12-88	
Accumulated Deferred Income Taxes — Accelerated Amortization Property	272 - 273	Ed. 12-96	
Accumulated Deferred Income Taxes -- Other Property	274 - 275	Ed. 12-96	
Accumulated Deferred Income Taxes — Other	276 - 277	Ed. 12-96	
Other Regulatory Liabilities	278	Ed. 12-94	
INCOME ACCOUNT SUPPORTING SCHEDULES			
Electric Operating Revenues	300 - 301	Ed. 12-96	
Sales of Electricity by Rate Schedules	304	Ed. 12-95	
Sales of Resale	310 - 311	Ed. 12-88	
Electric Operation and Maintenance Expenses	320 - 323	Ed. 12-95	
Number of Electric Department Employees	323	Ed. 12-93	
Purchased Power	326 - 327	Ed. 12-95	
Transmission of Electricity for Others	328 - 330	Ed. 12-90	
Transmission of Electricity by Others	332	Ed. 12-90	none
Miscellaneous General Expenses — Electric	335	Ed. 12-94	
Depreciation and Amortization of Electric Plant	336 - 337	Ed. 12-95	
Particulars Concerning Certain Income Deduction and Interest Charges Accounts	340	Ed. 12-87	
COMMON SECTION			
Regulatory Commission Expenses	350 - 351	Ed. 12-96	
Research, Development and Demonstration Activities	352 - 353	Ed. 12-87	
Distribution of Salaries and Wages	354 - 355	Ed. 12-88	
Common Utility Plant and Expenses	356	Ed. 12-87	
ELECTRIC PLANT STATISTICAL DATA			
Electric Energy Account	401	Rev. 12-90	
Monthly Peaks and Output	401	Rev. 12-90	
Steam-Electric Generating Plant Statistics (Large Plants)	402 - 403	Rev. 12-95	
Hydroelectric Generating Plant Statistics (Large Plants)	406 - 407	Ed. 12-89	none
Pumped Storage Generating Plant Statistics (Large Plants)	408 - 409	Ed. 12-88	
Generating Plant Statistics (Small Plants)	410 - 411	Ed. 12-87	

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
ELECTRIC PLANT STATISTICAL DATA (Continued)			
Transmission Line Statistics	422 - 423	Ed. 12-87	
Transmission Lines Added During Year	424 - 425	Ed. 12-86	none
Substations	426 - 427	Ed. 12-96	
Electric Distribution Meters and Line Transformers	429	Ed. 12-88	
Environmental Protection Facilities	430	Ed. 12-88	
Environmental Protection Expenses	431	Ed. 12-88	
Footnote Data	450	Ed. 12-87	none

Stockholders' Reports *Check appropriate box:*

[X] Four copies will be submitted.

[ ] No annual report to stockholders is prepared.

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of the office where any other corporate books are kept, if different from that where the general corporate books are kept.

Thomas P. Hill, Jr., Vice President and Controller
2301 Market Street
Philadelphia, PA 19101

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Pennsylvania, October 31, 1929

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not applicable

4. State the classes of utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric and Gas Utility Service

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the the principal accountant for your previous year's certified financial statements?

Yes...Enter the date when such independent accountant was initially engaged:

x No

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.

2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.

3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

DEFINITIONS

1. See the Uniform System of Accounts for a definition of control.

2. Direct control is that which is exercised without interposition of an intermediary.

3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.

4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	PECO Energy Power Company	Owns and leases property to	100	Direct
2		PECO Energy Company		
3	Susquehanna Power Company	Owns and leases property to		(A)
4		Susquehanna Electric Co.		
5	The Proprietors of the Susquehanna Canal	Inactive		(B)
6	Susquehanna Electric Company	Electric service	100	Direct
7	PECO Wireless, Inc.	Owns 49% of AT&T Wireless PCS		Direct
8	PECO Energy Capital Corp.	General Partner for		Direct
9		PECO Energy Capital L.P.		
10	PECO Energy Capital L.P.	Investment L.P.		(C)
11	Eastern Pennsylvania Development Co.	Owns and provides capital to		Direct
12		subsidiaries		
13	Energy Performance Services, Inc.	Energy services company		(D)
14	Adwin Realty Company	Real estate development		(D)
15	Adwin Equipment Company	Equipment leasing and		(D)
16		cogeneration activity		
17	Adwin (Schuylkill) Cogeneration, Inc.	Special purpose company hold-		(E)
18		ing cogeneration interests		
19	Horizon Energy Company	Marketer of natural gas		Direct
20	Exelon Corporation	Energy services		Direct
21	Energy Trading Company	Owns 50% of Barter One, LLC		Direct
22	Eastern Pennsylvania Exploration Company	Gas Exploration	100	Direct
23				
24				
25				
26				
27				

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.

2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.

3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

DEFINITIONS

1. *See the Uniform System of Accounts for a definition* of control.

2. Direct control is that which is exercised without interposition of an intermediary.

3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.

4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	(A) Indirect - Controlled by PECO Energy Power			
2	Company which owns 100% of capital stock			
3	(B) Indirect - Controlled by Susquehanna Power			
4	Company which owns 100% of capital stock			
5	(C) Indirect - Controlled by PECO Energy			
6	Capital Corp.			
7	(D) Indirect - Controlled by Eastern			
8	Pennsylvania Development Corp which owns			
9	100% of capital stock			
10	(E) Indirect - Controlled by Adwin Equipment			
11	Company			
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policymaking functions.

2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chairman of the Board	J. F. Paquette, Jr.	$955,502
2	President and Chief Executive Officer	C. A. McNeill, Jr.	691,831
3	President and Chief Nuclear Officer	D. M. Smith	328,662
4	Senior Vice President, Consumer Energy Services Group	W. L. Bardeen	444,853
5	Senior Vice President, Legal and General Counsel	J. W. Durham	414,343
6	Senior Vice President, Human Resources	W. J. Kaschub	291,186
7	Senior Vice President, Corporate and Public Affairs	G. S. King	305,055
8	Senior Vice President and Chief Financial Officer	K. G. Lawrence	352,327
9	Senior Vice President, Power Generation Group	J. M. Madara, Jr.	293,249
10	Senior Vice President, Gas Services Group	R. J. Patrylo	290,217
11	Senior Vice President, Nuclear Operations	G. R. Rainey	249,590
12	Senior Vice President, Bulk Power Enterprises	A. J. Weigand	196,098
13	Vice President, Customer Services	J. M. Bauer	152,217
14	Vice President, Corporate Planning and Development	G. A. Cucchi	238,253
15	Vice President, Operations, Power Generation Group	J. Doering, Jr.	175,211
16	Vice President, Station Support	D. B. Fetters	192,434
17	Acting General Manager, Power Delivery	G. N. Dudkin	90,642
18	Vice President and Controller	T. P. Hill, Jr.	220,046
19	Vice President, Information Systems and		
20	Chief Information Officer	K. C. Holland	201,981
21	Vice President, Limerick Generating Station	W. G. MacFarland	226,405
22	Vice President, Finance and Treasury	J. B. Mitchell	202,846
23	Vice President, Peach Bottom Atomic Power Station	T. N. Mitchell *	
24	Vice President, Support Services	W. E. Powell, Jr.	108,794
25	Vice President, Telecommunications Group	W. H. Smith, III	234,262
26	Vice President, Marketing and Sales	D. A. Thomas	226,065
27	Vice President, Power Transactions	N. J. Zausner	334,814
28	Corporate Secretary	K. K. Combs	163,576
29	Assistant Corporate Secretary	E. J. Cullen, Jr.	140,088
30	Assistant Corporate Secretary	T. D. Cutler	103,852
31	Assistant Treasurer	D. T. Moy Kelly	118,193
32	Assistant Treasurer	G. R. Shicora	87,984
33			
34	* Not compensated by PECO Energy Company - Services		
35	provided by INPO.		
36			
37			
38			
39			
40			
41			
42			
43			
44			

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.

2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Susan W. Catherwood	622 Rose Lane
2		Bryn Mawr, PA 19010
3		
4	M. Walter D'Alessio	Legg Mason Real Estate Services, Mellon Bank Center 12th Floor
5		1735 Market Street
6		Philadelphia, PA 19103-7501
7		
8	G. Fred DiBona, Jr.	Independence Blue Cross
9		1901 Market Street
10		Philadelphia, PA 19103-1480
11		
12	R. Keith Elliott	Hercules, Inc., 1313 N. Market Street
13		Wilmington, Delaware 19894
14		
15		
16	Richard G. Gilmore ***	948 Kennett Way, Hershey's Mill
17		West Chester, PA 19380
18		
19	Richard H. Glanton, Esq. ***	Reed Smith Shaw & McClay, 2500 One Liberty Place
20		1650 Market Street
21		Philadephia, PA 19103
22		
23	James A. Hagen	CONRAIL, Inc., Two Commerce Square
24		2001 Market Street - 17th Floor, P.O. Box 41417
25		Philadelphia, PA 19101-1417
26		
27	Nelson G. Harris, Esq. ***	Tasty Baking Company, Bala Pointe Office Centre, Suite 232
28		111 Presidential Boulevard
29		Bala Cynwyd, PA 19004
30		
31	Joseph C. Ladd	1111 Beech Road, Rosemont, PA 19010
32		
33	Edithe J. Levit, M.D.	National Board of Medical Examiners, The Rittenhouse - 2305
34		210 West Rittenhouse Square, Philadelphia, PA 19103
35		
36	Adm. Kinnaird R. McKee, USN (Ret.)	U.S. Navy Nuclear Propulsion, 214 South Morris Street
37		P. O. Box 610, Oxford, MD 21654-0610
38		
39	Joseph J. McLaughlin ***	655 N. Ithan Avenue, Rosemont, PA 19010
40		
41	Corbin A. McNeill, Jr. ***	2301 Market Street
42	President and Chief Executive Officer	Philadelphia, PA 19101
43		
44	John M. Palms, PhD	University of South Carolina
45		Office of the President
46		Corner of Bull and Pendleton Sts., Rm. 203
47		Columbia, SC 29208
48		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [x] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.

2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Joseph F. Paquette, Jr. **	2301 Market Street
2	Chairman of the Board	Philadelphia, PA 19101
3		
4	Ronald Rubin ***	The Rubin Organization, Inc.
5		200 South Broad Street
6		3rd Floor
7		Philadelphia, PA 19102
8		
9	Robert Subin	Global Sourcing and Engineering
10		Campbell Soup Company
11		Campbell Place - 5
12		Camden, NJ 08103
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46		
47		
48		

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SECURITY HOLDERS AND VOTING POWERS

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year had the highest voting powers in the respondent, and state the number of votes which each would have had the right to cast on that date if a meeting were then in order. If any such holder held in trust, give in a footnote the known particulars of the trust(whether voting trust, etc.) duration of trust, and principal holders of beneficiary interests in the trust. If the stock book was not closed or a list of stockholders was not compiled within one year prior to the end of the year, or if since the previous compilation of a list of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.

2. If any security other than stock carries voting rights, explain in a footnote the circumstances whereby such security became vested with voting rights and give other important particulars (details) concerning the voting rights of such security. State whether voting rights are actual or contingent; if contingent, describe the contingency.

3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.

4. Furnish particulars (details) concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or rights. Specify the amount of such securities or assets so entitled to be purchased by any officer, director, associated company, or any of the ten largest security holders. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants, or rights were issued on a prorata basis.

1. Give date of the latest closing of the stock book prior to end of year, and state the purpose of such closing:	2. State the total number of votes cast at the latest general meeting prior to end of year for election of directors or the respondent and number of such votes cast by proxy	3. Give the date and place of such meeting:
Stock Books do not close	Total: 183,935,439 By proxy: 183,935,439	April 10, 1996 Valley Forge Conv. Center 1200 First Avenue King of Prussia, PA

VOTING SECURITIES

Number of votes as of (date): February 7, 1997

Line No.	Name (Title) and Address of Security Holder (a)	Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
4	TOTAL votes of all voting securities	222,542,087	222,542,087		
5	TOTAL number of security holders	176,590	176,590		
6	TOTAL votes of Security holders listed below	176,946,058	176,946,058	0	0
7	Cede & Co. -M-	142,109,007	142,109,007		
8	P. O. Box 20				
9	Bowling Green Station				
10	New York, NY 10274				
11					
12	Stanley & Co. -M-	31,825,750	31,825,750		
13	P. O. Box 2598				
14	Jersey City, NJ 07303				
15					
16	Philadep -M-	1,548,308	1,548,308		
17	1900 Market Street, 2nd Floor				
18	Philadelphia, PA 19103				

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SECURITY HOLDERS AND VOTING POWERS (Continued)

Line No.	Name (Title) and Address of Security Holder (a)	Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
19	PECO Energy Company	878,745	878,745		
20	Trustee for 401K Common Stock Plan				
21	2301 Market Street S6-4				
22	Philadelphia, PA 19101				
23					
24	Allen W. Pike Trustee of the A.W. Pike	175,000	175,000		
25	Revocable Trust DTD 05-04-83				
26	20 Chestnut St., Apt. N-10				
27	Exeter, NH 03833				
28					
29	Hart Securities Ltd., Attn: A. Bonnano	110,000	110,000		
30	Gibson Dunn & Crutcher				
31	1050 Connecticut Ave. NW, 900				
32	Washington, DC 20036				
33					
34	Chelsea Milling Co. c/o Prudential Sec.	104,700	104,700		
35	400 Renaissance Ctr., Suite 1600				
36	Detroit, MI 48243				
37					
38	Biagio Demento & Cosima	81,421	81,421		
39	Demento Jt Ten				
40	829 Paddock Drive				
41	Newtown Square, PA 19073				
42					
43	Tampa Farm Services Inc.	62,000	62,000		
44	P.O. Box 600				
45	Dover, FL 33527				
46					
47	Clarence B. Bowman & Regena M. Bowman	51,127	51,127		
48	Jt Ten				
49	68 Brennan Drive				
50	Bryn Mawr, PA 19010				
51					
52					
53					

IMPORTANT CHANGES DURING THE YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none" "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefor and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.

2. *Acquisition of ownership in other companies by* reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.

3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform system of Accounts were submitted to the Commission.

4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other conditions. State name of Commission authorizing lease and give reference to such authorization.

5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements etc.

6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and *the amount of obligation or guarantee.*

7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.

8. State the estimated annual effect and nature of any important wage scale changes during the year.

9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.

10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on page 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.

11. (Reserved.)

12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by instructions 1 to 11 above, such notes may be included on this page.

PAGE 108 INTENTIONALLY LEFT BLANK

SEE PAGE 109 FOR REQUIRED INFORMATION

IMPORTANT CHANGES DURING THE YEAR (Continued)

1. None
2. None
3. None
4. None
5. None
6. None
7. None

8. A general wage increase of 3.5% was granted to regular and probationary employees, to be effective January 1, 1997. This did not apply to exempt non-compensable employees.

9. See response to item 12.

10. None
11. None

12. IMPORTANT CHANGES DURING THE YEAR

Deregulation and Rate Matters

In 1996, approximately 86% of the Company's electric sales revenue and 100% of its gas sales revenue were derived pursuant to rates regulated by the Pennsylvania Public Utility Commission (PUC) and approximately 13% of the Company's electric revenue was derived pursuant to rates regulated by the Federal Energy Regulatory Commission (FERC). The PUC has established through regulatory proceedings the base rates which the Company may charge for electric and gas service in Pennsylvania. In addition, the PUC has regulated various fuel and tax adjustment clauses applicable to customers' bills.

In response to competitive pressures, the Company has continued to negotiate long-term contracts with many of its large volume industrial customers. Although these agreements have resulted in reduced margins, they have permitted the Company to retain these customers. During 1996, energy sales under long-term contracts were 8% of total electric sales. With the development of the wholesale generation market, the Company has increased both its wholesale power purchases and sales.

As a result of the adoption of the Electricity Generation Customer Choice and Competition Act (Competition Act), and deregulation initiatives by FERC, as described below, the Company anticipates the unbundling of electric services into separate generation, transmission and distribution services with open competition for both wholesale and retail generation services. The Company believes that the Competition Act and other regulatory

IMPORTANT CHANGES DURING THE YEAR (Continued)

initiatives that provide for competition for generation services will significantly affect the Company's future financial condition and results of operations. Because of the substantial capital costs of its investment in nuclear generation, the Company is a high-cost producer. However, because of the fuel and other economies of nuclear generation, the Company is a relatively low marginal cost producer. At this time the Company cannot predict whether the changes resulting from deregulation of generation services will materially affect the market prices of its publicly traded securities.

Electric - Retail

The Competition Act was enacted in December 1996, providing for the restructuring of the electric utility industry in Pennsylvania. The Competition Act requires the unbundling of electric services into separate generation, transmission and distribution services with open retail competition for generation. Electric distribution and transmission services are to remain regulated by the PUC. The Competition Act requires utilities to submit to the PUC restructuring plans, including their stranded costs which will result from competition. Stranded costs include regulatory assets, nuclear decommissioning costs and long-term purchased power commitments, for which full recovery is allowed, and other costs, including investment in generating plants, spent-fuel disposal, retirement costs and reorganization costs, for which an opportunity for recovery is allowed in an amount determined by the PUC as just and reasonable. These costs, after mitigation by the utility, are to be recovered through the Competitive Transition Charge (CTC) approved by the PUC and collected from distribution customers for up to nine years (or for an alternative period determined by the PUC for good cause shown). During that period, the utility is subject to a rate cap which provides that total charges to customers cannot exceed the rates in place as of December 31, 1996, subject to certain exceptions. To the extent the Company is not ultimately permitted by the PUC to recover its retail electric stranded costs, this amount could result in a charge against earnings and a subsequent reduction in revenues.

Full electric generation competition will be phased in for one-third of each customer class by January 1, 1999, for an additional one-third by January 1, 2000 and for all remaining customers by January 1, 2001.

On March 18, 1997, certain intervenors petitioned the

IMPORTANT CHANGES DURING THE YEAR (Continued)

Commonwealth Court of Pennsylvania to enjoin the PUC from taking any action or rendering any decision pursuant to the Competition Act. The Company cannot predict the outcome of this matter.

The Competition Act also authorizes the PUC to approve, by adopting a qualified rate order (QRO), the issuance by a utility, a finance subsidiary of a utility or a third party assignee of a utility of Transition Bonds as a mechanism to mitigate stranded investment and reduce customer rates. Under the Competition Act, proceeds of Transition Bonds are required to be used principally to reduce qualified stranded costs and the related capitalization of the utility. The Transition Bonds are repayable from the irrevocable Intangible Transition Charges (ITC). The maximum maturity of the Transition Bonds is ten years.

On January 22, 1997, the Company filed an Application with the PUC for a QRO authorizing the issuance of Transition Bonds to fund $3.6 billion of stranded costs and related transaction and use of proceeds costs. The Company requested expedited review of its Application under the Competition Act, which requires the PUC to complete its review of the Application and issue a final determination within 120 days.

The Application, which was filed in advance of the Company's required restructuring filing, seeks recovery of $3.6 billion of the Company's estimated $7.1 billion (at December 31, 1998) total stranded costs through the issuance of the Transition Bonds covered by the Application. As a result of an updated market valuation of the Company's generating plant, the Company has reduced its total stranded cost claim from $7.1 to $6.7 billion. The Company's current estimate of total stranded costs includes $3.5 billion of generation assets, $560 million of unfunded and as yet unrecorded decommissioning expense and $2.6 billion of regulatory assets. Recovery of the portion of the Company's stranded costs not recovered by the Application will be requested by the Company in its restructuring filing, which is presently anticipated to be made on April 1, 1997.

The Application sets forth the Company's proposal for issuance of the Transition Bonds through an unrelated special purpose entity in order to achieve off-balance sheet treatment of the transaction. In proposed transactions involving other utilities, the Securities and Exchange Commission has indicated that off-balance sheet treatment would not be permitted. The Company cannot predict whether off-balance sheet treatment will be permitted for the issuance of the Transition Bonds. If off-balance sheet treatment is not permitted, the Company proposes that the

IMPORTANT CHANGES DURING THE YEAR (Continued)

Transition Bonds be issued through a limited purpose finance subsidiary. The finance subsidiary would acquire from the Company the intangible transition property authorized under the Competition Act which represents the right to recover through the ITC stranded costs and related transaction and use of proceed costs. The finance subsidiary would pledge the intangible transition property and related ITC to secure the Transition Bonds. Thus, amounts received from the ITC would be dedicated exclusively to the payment of the Transition Bonds.

The Company proposes using the proceeds it receives resulting from the issuance of the Transition Bonds, to pay transaction and use of proceeds costs, currently estimated at $173 million, to settle deferred fuel balances of $240 million and to reduce capitalization by approximately $3.4 billion. The capitalization reduction would be approximately proportionate to the Company's current capitalization. Specific securities to be retired and the manner in which they are to be retired have not been determined and will depend on market conditions at the time of the issuance of the Transition Bonds.

Adoption by the PUC of the requested QRO and issuance of Transition Bonds to fund $3.6 billion of the Company's stranded costs and related issuance and use of proceeds costs at current interest rates would result in an estimated average 3.5% reduction in the Company's electric retail rates. The Company estimates that the consummation of the transaction as proposed in the Application and assuming the Company is permitted off-balance sheet treatment would reduce the Company's annual revenues by approximately $650 million and the Company's annual operating expense by $501 million, resulting in an estimated reduction in annual net income of $149 million. The reduction in revenue results from the elimination of the revenue requirements of stranded costs, and the reduction in operating expenses results from decreases in depreciation, interest expense and associated income taxes. The impact on the Company's earnings per share will depend on the price at which shares of the Company's Common Stock are purchased. If Common Stock is repurchased at a price above book value ($20.88 at December 31, 1996), earnings per share will be reduced. The PUC has assigned the matter of the QRO to an administrative law judge (ALJ) who has held hearings on the matter, A recommended decision by the ALJ is expected by April 15, 1997, and the PUC is expected to issue a decision with respect to the requested QRO by May 22, 1997. The Company cannot predict whether the PUC will issue the requested QRO, the level of stranded cost recovery authorized by any QRO or

IMPORTANT CHANGES DURING THE YEAR (Continued)

the amount of the Transition Bonds, if any, ultimately issued pursuant to any QRO.

Under the Competition Act, the Company's rates for transmission and distribution services will be capped at January 1, 1997 levels for 4.5 years and the generation portion of rates for up to nine years from the effective date of the Competition Act. In recognition of the capping of rates at current levels, at December 31, 1996, the PUC approved the Company's request to roll-in and eliminate the Energy Cost Adjustment (ECA), a billing surcharge mechanism previously used to recover a portion of the Company's energy costs. In addition, the PUC recognized the Company's right to defer and, in the future, seek recovery of (1) an estimated $102 million attributable to its undercollection of $80 million in energy costs through 1996 and the anticipated $22 million performance bonus with respect to the 1996 operation of the Company's nuclear generating facilities, and (2) approximately $198 million of future energy costs that would not have otherwise been recoverable. Subject to the rate cap limitations imposed by the Competition Act, the PUC provided that these deferred amounts may be recovered either through the stranded cost recovery mechanisms provided in the Competition Act or an automatic adjustment clause provided in the Public Utility Code. On February 26, 1997, a coalition of the Company's large industrial customers petitioned the PUC to reconsider and amend its order regarding the ECA.

On February 27, 1997, in compliance with the Competition Act, the Company filed with the PUC a comprehensive pilot program to enable some 90,000 residential, commercial and industrial customers to choose their electric generation suppliers beginning as early as October 1997. The cross section of eligible customers will include 5 percent from the City of Philadelphia and 5 percent from suburban counties across all major rate classes. Also, residential customers in one randomly selected township or borough in the suburbs and one randomly selected political subdivision in the City of Philadelphia will be eligible. In addition, randomly selected commercial and industrial customers located in state-created Enterprise Zones will be eligible. Power would be delivered to the pilot customers as early as October 1997, and no later than January 1998. The pilot would conclude in December 1998. All pilot participants would be among the one-third of electric utility customers to be offered choice by January 1, 1999.

If approved by the PUC, the pilot would begin in April 1997, with the random selection by a neutral third party of

IMPORTANT CHANGES DURING THE YEAR (Continued)

some 90,000 customers from the Company's service territory. Under the pilot, the 90,000 customers will have the opportunity to buy their electricity from other power companies, brokers or marketers through 1998. Cumulatively, about 480 MW of electric load will be open to competition. The power from other suppliers would continue to be delivered over the Company's transmission and distribution lines, and the Company would continue to supply customer services such as meter reading, billing and outage restoration.

On February 22, 1996, the PUC approved the Company's petition for a declaratory order to change the estimated depreciable lives of certain of the Company's electric plant. The order approved the reduction of the terminal dates by ten years, for depreciation accrual purposes only, of Limerick Units No. 1 and No. 2 and associated common facilities, the utilization of new life spans for various categories of electric production plant and changes in the remaining life estimates for transmission, distribution, general and common plant. The order also approved the amortization over a nine-year period of $331 million of deferred Limerick costs representing $240 million of carrying charges and depreciation associated with 50% of Limerick common facilities and $91 million of operating and maintenance expenses, depreciation and accrued carrying charges on the Company's capital investment in Limerick Unit No. 2 and 50% of Limerick common facilities during the period from January 8, 1990, the commercial operation date of Limerick Unit No. 2, until April 20, 1990, the effective date of the inclusion of Limerick Unit No. 2 in base rates. The changes, which were effective October 1, 1996, increase depreciation and amortization on assets associated with Limerick by approximately $100 million per year and decrease depreciation and amortization on other Company assets by approximately $10 million per year, for a net increase in depreciation and amortization of approximately $90 million per year. The order did not increase rates charged to customers.

Electric - Wholesale

During 1996, the FERC issued Order No. 888 which required public utilities to file open-access transmission tariffs for wholesale transmission services in accordance with non-discriminatory terms and conditions established by the FERC. The FERC's new rules provide for the recovery of legitimate and verifiable wholesale stranded costs.

In response to Order No. 888, the Company and other

IMPORTANT CHANGES DURING THE YEAR (Continued)

members of the Pennsylvania-New Jersey-Maryland Interconnection Association (PJM) submitted to the FERC separate filings proposing to restructure the PJM. The Company proposed five major initiatives to reduce the costs of electricity while preserving the reliability and universal service that is essential to Pennsylvania citizens. In November 1996, the FERC issued an order rejecting both of the PJM restructuring filings. The FERC identified two issues that remain to be resolved: independence of the independent system operator; and open access transmission pricing tariffs that are nondiscriminatory. The FERC directed the parties to refile their proposals, preferably as one proposal, resolving these issues by December 31, 1996, with tariffs to be effective March 1, 1997. On December 31, 1996, the PJM member companies, including the Company, filed a joint compliance open-access transmission tariff with the FERC. The filing was not a complete consensus but included competing proposals in certain areas such as transmission rate structure and transmission constraint/congestion control. The PJM member companies requested the FERC to choose between the options for implementation during the interim period. On February 28, 1997, the FERC issued an order advising the PJM companies of which options to implement and making the PJM pool compliance filing, as revised by the FERC, effective March 1, 1997, subject to refund. In doing so, the FERC adopted, at least for an interim period, the congestion pricing model which had been proposed by the Company. Further, the FERC advised the PJM companies and other intervenors that it intended to convene a technical conference to address pricing issues related to the PJM pool operations.

The Company received approval for its transmission service tariff covering network and point-to-point services and a market-based rate energy sales tariff that allows the Company to sell wholesale energy at market-based rates outside the PJM control area. During the latter part of 1996, the Company also requested approval from the FERC of certain modifications to the Company's buy-for-resale tariff. The requested modifications would remove the existing cost-based cap on prices charged for power purchased by the Company in anticipation of later resale in the wholesale market and change certain of its terms. The transactions covered under the original market-based rate tariff would be rolled into the amended buy-for-resale tariff. Approval of the new tariff provisions will allow the Company to purchase and re-sell energy at market-based rates both within the PJM and outside the PJM.

IMPORTANT CHANGES DURING THE YEAR (Continued)

Gas

The gas industry is continuing to undergo structural changes in response to the FERC policies designed to increase competition. This has included requirements that interstate gas pipelines unbundle their gas sales service from other regulated tariff services, such as transportation and storage. In anticipation of these changes, the Company has modified its gas purchasing arrangements to enable the purchase of gas and transportation at lower cost.

On May 31, 1996, the Company filed Purchased Gas Cost (PGC) No. 13 rates for the period December 1, 1996 through November 30, 1997, which reflected a $0.79 per thousand cubic feet (mcf) increase in natural gas sales rates. On July 15, 1996, a settlement was reached with interested parties to accept the proposed PGC No. 13 rates, subject to updating procedures for more recent gas cost data. The settlement also includes: (1) an off-system sales program under which the net margin from off-system sales will be allocated 75% to PGC customers and 25% to the Company; (2) a futures market incentive program under which the risks and benefits of procuring natural gas on the basis of futures prices, in lieu of monthly spot prices, will be shared between PGC customers and the Company. Both programs are effective from April 15, 1995 and extend through March 31, 1998.

On March 31, 1997, the Company filed its quarterly update of PGC No. 13 rates for the period March 1, 1997 through May 31, 1997, which reflects a $0.42 per mcf increase in natural gas sales rates.

Shutdown of Salem Generating Station (Salem)

Salem Units No. 1 and No. 2 have not operated since the second quarter of 1995, when they were removed from service by Public Service Electric and Gas Company (PSE&G). At that time, PSE&G informed the Nuclear Regulatory Commission (NRC) that it had determined to keep the Salem units shut down pending review and resolution of certain equipment and management issues and NRC agreement that each unit is sufficiently prepared to restart. PSE&G estimates the projected restart of Unit No. 2 to occur in the second quarter of 1997 and of Unit No. 1 to occur in the fall of 1997. Because the timing of restart for the Salem units is subject to satisfactory completion of the requirements of the restart plan, as determined by PSE&G and the NRC, no assurance can be given that the projected restart date will

IMPORTANT CHANGES DURING THE YEAR (Continued)

be met. As of December 31, 1996 and 1995, the Company had incurred and expensed $149 and $50 million, respectively, for replacement power and maintenance costs related to the shutdown of Salem. The Company continues to incur replacement power costs of approximately $5 million per month per unit associated with the outage of the Salem units. The inability to successfully return the Salem units to service could have a material adverse effect on the Company's financial position or results of operations.

The Company has been informed by PSE&G that as a part of PSE&G's efforts to return the Salem units to service, during 1996, an examination was performed on the steam generators, which are large heat exchangers used to produce steam to drive the turbines. Inspection of Salem Unit No. 1 indicated degradation in a significant number of tubes. Inspection and testing of Salem Unit No. 2 confirmed that the condition of the steam generators are well within current repair limits. The Salem co-owners have purchased and installed in Salem Unit No. 1 unused steam generators from the unfinished Seabrook Nuclear Generating Station Unit No. 2 in New Hampshire. PSE&G's estimate of the cost of replacing, including installing the Salem Unit No. 1 steam generators is approximately $150 to $170 million, of which the Company's share is approximately $64 to 72 million. In addition, the cost of disposal of the four old steam generators could be as much as $20 million, of which the Company's share is approximately $9 million.

A recent generic letter from the NRC identified an issue that may further impact the Salem Unit No. 2 startup schedule. The generic letter requested all nuclear utilities to review systems for potential waterhammer events (hydrodynamic stress caused by steam formation in a piping system) and the impact that these events could have on the system's safety function. PSE&G has determined that, in order to address the concerns of the generic letter, modifications are necessary to the containment fan coil units of Salem Units No. 1 and No. 2, which provide containment air cooling. As a result of installation of these modifications and the time required for NRC acceptance of PSE&G's proposed resolution of these issues, the restart of Salem Unit No. 2 may be delayed.

At the January 1997 semi-annual NRC Senior Management Meeting, the Salem units were placed on the "NRC Watch List" (Watch List) and were designated as Category 2 facilities. In a letter to PSE&G advising of the action, the NRC noted that its decision to place the Salem units on the Watch List was not based on any recent performance problems or decline but was due to the NRC's determination that the Salem units

IMPORTANT CHANGES DURING THE YEAR (Continued)

should have been placed on the Watch List previously because of Salem's past safety performance. The NRC also indicated in its letter that it had increased its attention and resources at Salem commensurate with a Watch List plant. Finally, the NRC concluded that, notwithstanding the improvements at Salem (which were noted), had it been previously identified as a Watch List plant, Salem would not have been removed from the Watch List since Salem had yet to demonstrate a period of safe performance at power. The NRC has three classifications of facility monitoring. A Category 3 facility is one which is having or has had significant weaknesses that warrant maintaining the plant in a shutdown condition until the licensee can demonstrate to the NRC that adequate programs have both been established and implemented to ensure substantial improvement. Full NRC approval is required for restart of plants in this category which the NRC will monitor closely. A Category 2 facility is a plant that is authorized to operate but that the NRC will monitor closely. Although being operated in a manner that adequately protects public health and safety, plants in this category are having or have had weaknesses that warrant increased NRC attention. A plant will remain in this category until the licensee either demonstrates a period of improved performance, or until a further deterioration of performance results in the plant being placed in Category 3. A Category 1 facility is a plant that has been removed from the Watch List.

On January 14, 1997, a United States Senator from Delaware wrote to the NRC to request the full NRC vote on the decision to restart the Salem units, rather than permit the NRC staff to authorize the restart under applicable NRC rules. By letter dated February 20, 1997, the NRC advised that is would not require a full NRC vote on the decision to restart Salem.

On March 5, 1996, the Company and Delmarva Power & Light Company (Delmarva) filed an action in the United States District Court for the Eastern District of Pennsylvania against Public Service Enterprise Group Incorporated and its subsidiary PSE&G (Enterprise Group) concerning the shutdown of Salem. The suit alleges that Enterprise Group breached the provisions of the Owners Agreement pursuant to which Enterprise Group operates Salem. The suit also alleges negligence, gross negligence, reckless, and willful and wanton misconduct. The plaintiffs seek compensation for certain replacement power costs they incurred as a result of the shutdown of Salem and for increased operating and maintenance costs and lost profits. Discovery in the case is scheduled to conclude in April

IMPORTANT CHANGES DURING THE YEAR (Continued)

1997. The case is expected to go to trial in 1997.

During the shutdown of Salem, examinations of the steam generator tubes at Salem Unit No. 1 revealed significant cracking. On February 27, 1996, the Company, PSE&G, Atlantic Electric Company and Delmarva, the co-owners of Salem, filed an action in the United States District Court for the District of New Jersey against Westinghouse Electric Corporation, the designer and manufacturer of the Salem steam generators. The suit alleges that the significant cracking of the steam generator tubes is the result of defects in the design and fabrication of the steam generators and that Westinghouse knew that the steam generators supplied to Salem were defective and that Westinghouse deliberately concealed this from PSE&G. The suit alleges violations of both federal and New Jersey Racketeer Influenced and Corrupt Organizations Acts (RICO), fraud, negligent misrepresentation and breach of contract.

Telecommunications

In a joint venture with Hyperion, a subsidiary of Adelphia Cable Company, the deployment of a large-scale fiber optic, cable-based telephone service in the Philadelphia region is approximately 80% complete. The Company's fiber optic cable currently extends over 400 miles and is connected to major long-distance carriers.

The Company is also aggressively completing the initial build-out of a new digital wireless Personal Communications Services (PCS) network in partnership with AT&T Wireless Services. Commercial launch of PCS in the Philadelphia area is scheduled for mid-1997. Due to the start-up nature of these joint ventures, investments in telecommunications will negatively affect earnings in the near future and are not expected to produce positive results for several years.

Employee Matters

On March 7, 1995, a New Jersey local of the International Brotherhood of Electrical Workers, AFL-CIO, (IBEW) filed two petitions with the National Labor Relations Board (NLRB) to hold certification elections to determine whether a group of production and maintenance employees from Eddystone Generating Station (Eddystone) and CrombyGenerating Station (Cromby) want the IBEW to serve as their collective bargaining representative. The petitions sought to establish separate bargaining units for 229

IMPORTANT CHANGES DURING THE YEAR (Continued)

employees, including operators, but excluded office clerical, professional, supervisory and management employees.

On March 22, 1995, the Utility Workers of America, AFL-CIO, (UWUA) filed a petition with the NLRB to hold a certification election to determine whether certain production and maintenance employees from Peach Bottom and Limerick, as well as the maintenance employees headquartered in the Company's Chesterbrook facility, want the UWUA to serve as their collective bargaining representative. The UWUA petition sought to establish a bargaining unit of approximately 840 employees composed of all maintenance employees and all control room operators, auxiliary operators, instrument and control technicians, health physics technicians, chemistry technicians, material handlers and technicians, and radioactive waste technicians. The petition excluded security guards, clerical and supervisory employees.

On October 2, 1995, the UWUA filed another petition seeking certification of a bargaining unit consisting of all production and maintenance employees of the Consumer Energy Services Group - the Company's customer service business unit.

On February 14, 1997, the NLRB issued its decision ruling that a union representation election does not require all hourly employees within the Company to vote as one unit. On the petitions filed by the IBEW, the NLRB ruled that while Eddystone and Cromby would not be appropriate bargaining units, the Company's Power Generation Group (PGG), which encompasses employees not only at Eddystone and Cromby but also eight smaller fossil-fuel plants located in the City of Philadelphia and its suburbs, the Conowingo Hydroelectric Station and Muddy Run Pumped Storage Project, would be an appropriate bargaining unit. The NLRB ruled similarly that a separate bargaining unit comprised of the Company's Nuclear Generating Group (NGG) (since renamed "PECO Nuclear") would be appropriate.

On February 24, 1997, the NLRB established March 24, 1997 as the date for the UWUA/PECO Nuclear election. On March 25, 1997, the NLRB announced that PECO Nuclear employees voted to continue not to be represented by a union. Employees cast 695 votes for 'no union,' 228 votes for the UWUA. The results are not official until the NLRB certifies the election. All parties involved in the election have seven days to contest the results. The IBEW/PGG petitions were remanded back to the NLRB's Regional Director to determine whether the IBEW has the requisite 30 percent showing of support within the PGG bargaining unit.

IMPORTANT CHANGES DURING THE YEAR (Continued)

The Company and its subsidiaries had 7,186 employees at December 31, 1996.

New Accounting Pronouncements

NRC regulations require that licensees of nuclear generating facilities demonstrate that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility. The PUC, based on estimates of decommissioning costs for each of the nuclear facilities in which the Company has an ownership interest, permits the Company to collect from its customers and deposit in segregated accounts amounts which, together with earnings thereon, will be used to decommission such nuclear facilities. The Company's 1990 estimate of its nuclear facilities' decommissioning costs of $643 million is being collected through electric base rates over the life of each generating unit. Under current rates, the Company collects and expenses approximately $20 million annually from customers for decommissioning the Company's ownership portion of its nuclear units. At December 31, 1996, the Company held $266 million in trust accounts, representing amounts recovered from customers and net realized and unrealized investment earnings thereon, to fund future decommissioning costs. The Company's most recent estimate, made in 1995, of its share of the cost to decommission its nuclear units is $1.4 billion in 1995 dollars. The Company has included the unfunded and as yet unrecorded portion of its estimated decommissioning costs in its estimate of stranded costs included in the January 22, 1997 application with the PUC for a QRO, although such recovery is not assured.

In an exposure draft issued in 1996, the Financial Accounting Standards Board (FASB) proposed changes in the accounting for closure and removal costs of production facilities, including the recognition, measurement and classification of decommissioning costs for nuclear generating stations. The FASB is currently considering expanding the scope of the Exposure Draft to include closure or removal liabilities that are incurred at any time in the operating life of the long-lived asset. The FASB plans to issue either a final Statement or a revised Exposure Draft in the second quarter of 1997. If current electric utility industry accounting practices for decommissioning are changed, annual provisions for decommissioning could increase and the estimated cost for decommissioning could be recorded as a liability rather than as accumulated

IMPORTANT CHANGES DURING THE YEAR (Continued)

depreciation with recognition of an increase in the cost of the related asset.

Effective January 1, 1996, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," which subjects long-lived assets to periodic analysis for impairment. No loss from impairment has been recorded in 1996.

Effective January 1, 1996, the Company adopted SFAS No. 123, "Accounting for Stock-Based Compensation," which encourages recognizing compensation costs for stock-based employee compensation plans using the fair value based method of accounting defined in SFAS No. 123. The Company has adopted the disclosure-only provisions of SFAS No. 123, but applies Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" and related interpretations in accounting for its Long-Term Incentive Plan.

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	$14,569,072,097	$14,817,472,182
3	Construction Work in Progress (107)	200-201	490,746,398	648,692,609
4	TOTAL UTILITY PLANT (Enter Total of lines 2 and 3)		$15,059,818,495	$15,466,164,791
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	4,585,175,273	5,010,636,480
6	Net Utility Plant (Enter Total of line 4 Less 5)	-	$10,474,643,222	$10,455,528,311
7	Nuclear Fuel (120.1-120.4, 120.6)	202-203	975,810,455	1,045,103,953
8	(Less) Accum. Prov. for Amort. of Nucl. Assemblies (120.5)	202-203	604,867,680	663,935,456
9	Net Nuclear Fuel (Enter Total of lines 7 Less 8)	-	$370,942,775	$381,168,497
10	Net Utility Plant (Enter Total of lines 6 and 9)	-	$10,845,585,997	$10,836,696,808
11	Utility Plant Adjustments (116)	122		
12	Gas Stored Underground-Noncurrent (117)	-		
13	OTHER PROPERTY AND INVESTMENTS			
14	Nonutility Property (121)	221	30,018,694	30,626,710
15	(Less) Accum. Prov. for Depr. and Amort. (122)	-	4,587,354	5,653,862
16	Investments in Associated Companies (123)	-	60,000	60,000
17	Investment in Subsidiary Companies (123.1)	224-225	169,825,876	272,707,987
18	(For Cost of Account 123.1, See Footnote Page 224, Line 42)	-		
19	Noncurrent Portion of Allowances	228-229		
20	Other Investments (124)		6,423,777	15,863,178
21	Special Funds (125-128)	-	222,655,396	268,111,830
22	TOTAL Other Property and Investments (Total of lines 14—17,19—21)		$424,396,389	$581,715,843
23	CURRENT AND ACCRUED ASSETS			
24	Cash (131)	-	(20,492,839)	(22,300,448)
25	Special Deposits (132-134)	-	1,966,456	735,829
26	Working Fund (135)	-	35,698,293	42,771,693
27	Temporary Cash Investments (136)	-	(31)	(31)
28	Notes Receivable (141)		395,623	392,806
29	Customer Accounts Receivable (142)	-	46,132,150	30,255,773
30	Other Accounts Receivable (143)	-	71,139,047	73,532,313
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	-	118,525,127	128,458,999
32	Notes Receivable from Associated Companies (145)	-		
33	Accounts Receivable from Assoc. Companies (146)	-	11,389,423	2,725,380
34	Fuel Stock (151)	227	46,282,517	34,570,861
35	Fuel Stock Expenses Undistributed (152)	227	294,302	384,665
36	Residuals (Elec) and Extracted Products (153)	227		
37	Plant Materials and Operating Supplies (154)	227	119,088,314	118,402,531
38	Merchandise (155)	227		
39	Other Materials and Supplies (156)	227		
40	Nuclear Materials Held for Sale (157)	202-203/227		
41	Allowances (158.1 and 158.2)	228-229	898,600	659,607
42	(Less) Noncurrent Portion of Allowances	228-229		
43	Stores Expense Undistributed (163)	-	3,830,002	916,740
44	Gas Stored Underground-Current (164.1)	-	28,640,737	46,618,567
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)	-	2,143,233	2,399,563
46	Prepayments (165)	-	25,684,145	25,188,803
47	Advances for Gas (166-167)	-		
48	Interest and Dividends Receivable (171)	-		
49	Rents Receivable (172)	-		
50	Accrued Utility Revenues (173)	-	147,530,000	117,330,000
51	Miscellaneous Current and Accrued Assets (174)		88,212,336	159,374,477
52	TOTAL Current and Accrued Assets (Enter Total of lines 24 thru 51)		$490,307,181	$505,500,130

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
53	DEFERRED DEBITS			
54	Unamortized Debt Expenses (181)	-	$18,448,141	$21,711,727
55	Extraordinary Property Losses (182.1)	230		
56	Unrecovered Plant and Regulatory Study Costs (182.2)	230	41,396,218	39,406,286
57	Other Regulatory Assets (182.3)	232	2,389,057,845	2,626,506,733
58	Prelim. Survey and Investigation Charges (Electric) (183)	-	6,730,214	4,324,242
59	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)	-		
60	Clearing Accounts (184)	-	3,489,419	0
61	Temporary Facilities (185)	-		
62	Miscellaneous Deferred Debits (186)	233	481,932,497	412,876,243
63	Def. Losses from Disposition of Utility Plt. (187)	-		
64	Research, Devel. and Demonstration Expend. (188)	352-353	55,056	3,625
65	Unamortized Loss on Reacquired Debt (189)	-	308,576,588	283,852,553
66	Accumulated Deferred Income Taxes (190)	234	381,852,094	269,794,472
67	Unrecovered Purchased Gas Costs (191)	-		
68	TOTAL Deferred Debits (Enter Total of lines 54 thru 67)		$3,631,538,072	$3,658,475,881
69	TOTAL Assets and other Debits (Enter Total of lines 10,11,12, 22,52,and 68)		$15,391,827,639	$15,582,388,662

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

COMPARATIVE BALANCE SHEET (LIABILITES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	$3,506,312,537	$3,517,613,980
3	Preferred Stock Issued (204)	250-251	292,067,425	292,067,425
4	Capital Stock Subscribed (202, 205)	252		
5	Stock Liability for Conversion (203, 206)	252		
6	Premium on Capital Stock (207)	252	1,213,910	1,213,910
7	Other Paid-in Capital (208-211)	253	57,668	57,668
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254		
11	Retained Earnings (215, 215.1, 216)	118-119	1,003,132,742	1,106,358,825
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	30,947,553	31,054,121
13	(Less) Reacquired Capital Stock (217)	250-251	219	219
14	TOTAL Proprietary Capital (Enter Total of Lines 2 thru 13)	-	$4,833,731,616	$4,948,365,710
15	LONG-TERM DEBT			
16	Bonds (221)	256-257	4,132,692,964	4,094,630,464
17	(Less) Reacquired Bonds (222)	256-257		
18	Advances from Associated Companies (223)	256-257	30,861,296	30,861,296
19	Other Long-Term Debt (224)	256-257	807,800,902	462,105,000
20	Unamortized Premium on Long-Term Debt (225)	-	9,580	7,972
21	(Less) Unamortized Discount on Long-Term Debt-Debit (226)	-	32,609,058	29,313,565
22	TOTAL Long-Term Debt (Enter Total of Lines 16 thru 21)	-	$4,938,755,684	$4,558,291,167
23	OTHER NONCURRENT LIABILITIES			
24	Obligations Under Capital Leases-Noncurrent (227)	-	120,104,848	132,740,877
25	Accumulated Provision for Property Insurance (228.1)	-		
26	Accumulated Provision for Injuries and Damages (228.2)	-		
27	Accumulated Provision for Pensions and Benefits (228.3)	-	325,659,662	314,466,441
28	Accumulated Miscellaneous Operating Provisions (228.4)	-	54,432,511	50,520,935
29	Accumulated Provision for Rate Refunds (229)	-		
30	TOTAL OTHER Noncurrent Liabilities (Enter Total of lines 24 thru 29)		$500,197,021	$497,728,253
31	CURRENT AND ACCRUED LIABILITIES			
32	Notes Payable (231)	-	0	287,500,000
33	Accounts Payable (232)	-	497,463,840	417,024,941
34	Notes Payable to Associated Companies (233)	-	0	0
35	Account Payable to Associated Companies (234)	-	2,366,975	2,813,878
36	Customer Deposits (235)	-	11,470,413	13,636,609
37	Taxes Accrued (236)	262-263	105,063,958	66,929,641
38	Interest Accrued (237)	-	88,057,922	82,016,817
39	Dividends Declared (238)	-	20,722,383	22,406,859
40	Matured Long-Term Debt (239)	-		
41	Matured Interests (240)	-		
42	Tax Collections Payable (241)	-	6,850,662	5,456,254
43	Miscellaneous Current and Accrued Liabilities (242)		76,788,632	86,829,429
44	Obligations Under Capital Leases-Current (243)		60,319,658	49,347,088
45	TOTAL Current and Accrued Liabilities(Enter Total of lines 32 thru 44)		$869,104,443	$1,033,961,516

Name of Respondent PECO Energy Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
46	DEFERRED CREDITS			
47	Customer Advances for Construction (252)		$2,542,902	$2,451,261
48	Accumulated Deferred Investment Tax Credits (255)	266-267	350,619,066	335,198,193
49	Deferred Gains from Disposition of Utility Plant (256)			
50	Other Deferred Credits (253)	269	191,481,343	187,838,461
51	Other Regulatory Liabilities (254)	278	20,978,232	22,075,261
52	Unamortized Gain on Reacquired Debt (257)	269	3,163,386	2,287,535
53	Accumulated Deferred Income Taxes (281-283)	272-277	3,681,253,946	3,994,191,305
54	TOTAL Deferred Credits (Enter Total of Lines 47 thru 53)		$4,250,038,875	$4,544,042,016
55				
56				
57				
58				
59				
60				
61				
62				
63				
64				
65				
66				
67				
68	TOTAL Liabilities and Other Credits (Enter Total of Lines 14, 22, 30, 45 and 54)		$15,391,827,639	$15,582,388,662

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from *Utility Plant Leased to Others*, in another Utility column (i,k,m,o) in a similar manner to a utility department. Spread the amount(s) over lines 02 thru 24 as appropriate. Include these amounts in columns (c) and (d) totals.

2. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

3. Report data for lines 7,9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

4. Use pages 122-123 for important notes regarding the statement of income or any account thereof.

5. Give concise explanations concerning unsettled rate *proceedings where a contingency exists such that refunds* of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power and gas purchases.

6. Give concise explanations concerning significant amounts of any refunds made or received duing the year.

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	*Operating Revenues (400)*	300-301	$4,282,129,850	$4,164,294,980
3	Operating Expenses			
4	Operation Expenses (401)	320-323	1,942,732,709	1,713,871,897
5	Maintenance Expenses (402)	320-323	320,241,113	302,711,027
6	Depreciation Expense (403)	336-337	442,504,370	420,188,621
7	Amort. & Depl. of Utility Plant (404-405)	336-337	42,908,891	32,126,895
8	Amort. of Utility Plant Acq. Adj. (406)	336-337	0	0
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)		1,930,318	1,877,204
10	Amort. of Conversion Expenses (407)		0	0
11	Regulatory Debits (407.3)		0	0
12	(Less) Regulatory Credits (407.4)		55,379	0
13	*Taxes Other Than Income Taxes (408.1)*	262-263	296,261,386	308,026,590
14	Income Taxes - Federal (409.1)	262-263	121,322,440	162,188,047
15	- Other (409.1)	262-263	62,434,683	71,469,583
16	Provision for Deferred Income Taxes (410.1)	234,272-277	176,182,070	177,127,372
17	(Less) Provision for Deferred Income Taxes - Cr. (411.1)	234,272-277	7,988,586	(3,047,464)
18	Investment Tax Credit Adj. - Net (411.4)	266	(15,962,659)	(21,629,908)
19	(Less) Gains from Disp. of Utility Plant (411.6)		2,103	404,497
20	Losses from Disp. of Utility Plant (411.7)		0	504
21	(Less) Gains from Disposition of Allowances (411.8)		73,924	0
22	Losses from Disposition of Allowances (411.9)		0	0
23	TOTAL Utility Operating Expenses (Enter Total of Lines 4 thru 22)		$3,382,435,329	$3,170,600,799
24	Net Utility Operating Income (Enter Total of line 2 less 23) (Carry forward to page 117, line 25)		$899,694,521	$993,694,181

STATEMENT OF INCOME FOR THE YEAR (Continued)

resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.

7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be included on pages 122-123.

8. Enter on pages 122-123 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.

9. Explain in a footnote if the previous year's figures are different from that reported in prior reports.

10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 23, and report the information in the blank space on pages 122-123 or in a footnote.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year (e)	Previous Year (f)	Current Year (g)	Previous Year (h)	Current Year (i)	Previous Year (j)	
						1
$3,853,315,771	$3,753,464,686	$428,814,079	$410,830,294			2
						3
1,678,965,918	1,454,075,405	263,766,791	259,796,492			4
307,161,490	286,821,313	13,079,623	15,889,714			5
416,791,043	394,681,015	25,713,327	25,507,606			6
41,936,551	31,373,511	972,340	753,384			7
0	0	0	0			8
1,930,318	1,877,204	0	0			9
0	0	0	0			10
0	0	0	0			11
55,379	0	0	0			12
270,054,696	281,718,816	26,206,690	26,307,774			13
104,836,436	134,600,581	16,486,004	27,587,466			14
62,060,223	67,896,534	374,460	3,573,049			15
168,422,828	192,496,322	7,759,242	(15,368,950)			16
9,439,332	(1,165,099)	(1,450,746)	(1,882,365)			17
(15,423,055)	(21,090,304)	(539,604)	(539,604)			18
2,103	404,497	0	0			19
0	504	0	0			20
73,924	0	0	0			21
0	0	0	0			22
$3,027,165,710	$2,825,211,503	$355,269,619	$345,389,296			23
$826,150,061	$928,253,183	$73,544,460	65,440,998			24

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	OTHER UTILITY		OTHER UTILITY		OTHER UTILITY	
	Current Year (k)	Previous Year (l)	Current Year (m)	Previous Year (n)	Current Year (o)	Previous Year (p)
1						
2	0	0				
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24	0	0				

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
25	Net Utility Operating Income (Carried forward from page 114)	—	$899,694,521	$993,694,181
26	Other Income and Deductions			
27	Other Income			
28	Nonutility Operating Income			
29	Revenues From Merchandising, Jobbing and Contract Work (415)		11,685,497	3,962,659
30	(Less) Costs and Exp. of Merchandising,Job. & Contract Work (416)		11,093,054	1,755,764
31	Revenues From Nonutility Operations (417)		1,117,350	0
32	(Less) Expenses of Nonutility Operations (417.1)		3,382,719	778,690
33	Nonoperating Rental Income (418)		(200,816)	(70,738)
34	Equity in Earnings of Subsidiary Companies (418.1)	119	6,453,368	3,779,507
35	Interest and Dividend Income (419)		10,448,018	20,000,170
36	Allowance for Other Funds Used During Construction (419.1)		10,039,643	14,291,796
37	Miscellaneous Nonoperating Income (421)		99,221	545,358
38	Gain on Disposition of Property (421.1)		2,764,180	60,330,792
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		$27,930,688	$100,305,090
40	Other Income Deductions			
41	Loss on Disposition of Property (421.2)		(54,084)	1,712,934
42	Miscellaneous Amortization (425)	340	0	0
43	Miscellaneous Income Deductions (426.1-426.5)	340	10,647,586	13,286,526
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)		$10,593,502	$14,999,460
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)	262-263	693,761	434,508
47	Income Taxes - Federal (409.2)	262-263	(1,757,834)	19,575,668
48	Income Taxes - Other (409.2)	262-263	0	6,893,675
49	Provision for Deferred Inc. Taxes (410.2)	234,272-277	(1,287,157)	7,142,559
50	(Less) Provision for Deferred Income Taxes - Cr. (411.2)	234,272-277	1,412,273	0
51	Investment Tax Credit Adj. - Net (411.5)		0	0
52	(Less) Investment Tax Credits (420)		0	0
53	TOTAL Taxes on Other Income and Deduct. (Total of 46 thru 52)		($3,763,503)	$34,046,410
54	Net Other Income and Deductions (Enter Total of lines 39, 44, 53)		$21,100,689	$51,259,220
55	Interest Charges			
56	Interest on Long-Term Debt (427)		303,657,635	352,859,970
57	Amort. of Debt Disc. and Expense (428)		25,736,879	34,516,293
58	Amortization of Loss on Reacquired Debt (428.1)		0	0
59	(Less) Amort. of Premium on Debt - Credit (429)		1,608	1,608
60	(Less) Amortization of Gain on Reacquired Debt - Credit (429.1)		875,850	1,174,273
61	Interest on Debt to Assoc. Companies (430)	340	4,037,016	3,146,176
62	Other Interest Expense (431)	340	80,580,363	58,483,135
63	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		9,543,566	12,606,904
64	Net Interest Charges (Enter Total of lines 56 thru 63)		$403,590,869	$435,222,789
65	Income Before Extraordinary Items (Total of lines 25, 54 and 64)		$517,204,341	$609,730,612
66	Extraordinary Items			
67	Extraordinary Income (434)		0	0
68	(Less) Extraordinary Deductions (435)		0	0
69	Net Extraordinary Items (Enter Total of line 67 less line 68)		0	0
70	Income Taxes-Federal and Other (409.3)	262-263	0	0
71	Extraordinary Items After Taxes (Enter Total of line 69 less line 70)		0	0
72	Net Income (Enter Total of lines 65 and 71)		$517,204,341	$609,730,612

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the the year.

2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b).

3. State the purpose and amount of each reservation or appropriation of retained earnings.

4. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.

5. Show dividends for each class and series of capital stock.

6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.

7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.

8. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance - Beginning of Year		$1,003,132,742
2	Changes (Identify by prescribed retained earnings accounts)		
3	Adjustments to Retained Earnings (Account 439)		
4	Credit:		
5	Credit:		
6	Credit:		
7	Credit:		
8	Credit:		
9	TOTAL Credits to Retained Earnings (Acc. 439) (Total of lines 4 thru 8)		
10	Debit: Preferred Stock Redemption		(275,149)
11	Debit: LTIP Expenses		(2,027,737)
12	Debit:		
13	Debit:		
14	Debit:		
15	TOTAL Debits to Retained Earnings (Acc. 439) (Total of lines 10 thru 14)		($2,302,886)
16	Balance Transferred from Income (Account 433 less Account 418.1)		510,750,973
17	Appropriations of Retained Earnings (Account 436)		
18			
19			
20			
21			
22	TOTAL Appropriations of Retained Earnings (Acc. 436) (Total of lines 18 thru 21)		
23	Dividends Declared - Preferred Stock (Account 437)		
24			(21,041,873)
25			
26			
27			
28			
29	TOTAL Dividends Declared - Preferred Stock (Acct. 437) (Total of lines 24 thru 28)	*	(21,041,873)
30	Dividends Declared - Common Stock (Account 438)		
31			(390,526,931)
32			
33			
34			
35			
36	TOTAL Dividends Declared - Common Stock (Acct. 438) (Total of lines 31 thru 35)		($390,526,931)
37	Transfers from Acct. 216.1, Unappropriated Undistributed Subsidiary Earnings		6,346,800
38	Balance - End of Year (Total of lines 01, 09, 15, 16, 22, 29, 36, and 37)		$1,106,358,825

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

STATEMENT OF RETAINED EARNINGS FOR THE YEAR (Continued)

Line No.	Item (a)	Amount (b)
	APPROPRIATED RETAINED EARNINGS (Account 215) State balance and purpose of each appropriated retained earnings amount at end of year and give accounting entries for any applications of appropriated retained earnings during the year.	
39		
40		
41		
42		
43		
44		
45	TOTAL Appropriated Retained Earnings (Account 215)	
	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE,FEDERAL (Account 215.1) State below the total amount set aside through appropriations of retained earnings, as of the end of the year, in compliance with the provisions of Federally granted hydroelectric project licenses held by the respondent. If any reductions or changes other than the normal annual credits hereto have been made during the year, explain such items in a footnote.	
46	TOTAL Appropriated Retained Earnings - Amortization Reserve, Federal (Account 215.1)	
47	TOTAL Appropriated Retained Earnings (Account 215, 215.1) (Enter total of lines 45 and 46)	
48	TOTAL Retained Earnings (Account 215, 215.1, 216) (Enter total of lines 38 and 47)	$1,106,358,825
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (ACCOUNT 216.1)	
49	Balance - Beginning of Year (Debit or Credit)	30,947,553
50	Equity in Earnings for Year (Credit) (Account 418.1)	6,453,368
51	(Less) Dividends Received (Debit)	6,346,800
52	Other Changes (Explain)	0
53	Balance - End of Year (Total of Lines 49 Thru 52)	$31,054,121

< Page 118 Line 29 Column C >

DIVIDENDS DECLARED - Preferred Stock (Account 437)

$3.80 per share on 3.80% Series	$ 1,330,000
$4.30 per share on 4.30% Series	752,500
$4.40 per share on 4.40% Series	1,410,233
$4.68 per share on 4.68% Series	819,000
$6.12 per share on 6.12% Series	6,618,780
$7.48 per share on 7.48% Series	4,363,337
$7.96 per share on 7.96% Series	5,748,023
Total Dividends Declared - Preferred Stock	$21,041,873

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

STATEMENT OF CASH FLOWS

1. If the notes to the cash flow statement in the respondents annual stockholders report are applicable to this statement, such notes should be included in pages 122-123. Information about noncash investing and financing activities should be provided on pages 122-123. Provide also on pages 122-123 a reconciliation between "Cash and Cash Equivalents at End of Year" with related amounts on the balance sheet.
2. Under "Other" specify significant amounts and group others.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show on pages 122-123 the amount of interest paid (net of amounts capitalized) and income taxes paid.

Line No.	Description (See Instruction No. 5 for Explanation of Codes) (a)	Amounts (b)
1	Net Cash Flow from Operating Activities:	
2	Net Income (Line 72(c) on page 117)	$517,204,341
3	Noncash Charges (Credits) to Income:	
4	Depreciation and Depletion	442,504,370
5	Amortization of (Specify)	
6	Prop. Loss 1,930,318;Cap. Software 11,212,694; Nuc. Fuel 59,067,776	72,210,788
7	Def. Limerick Chgs. 29,944,500;Power Rerates 1,751,697	31,696,197
8	Deferred Income Taxes (Net)	424,994,981
9	Investment Tax Credit Adjustment (Net)	(15,420,873)
10	Net (Increase) Decrease in Receivables	32,083,843
11	Net (Increase) Decrease in Inventory	(3,013,822)
12	Net (Increase) Decrease in Allowances Inventory	238,993
13	Net Increase (Decrease) in Payables and Accrued Expenses	(111,670,357)
14	Net (Increase) Decrease in Other Regulatory Assets	(237,448,888)
15	Net Increase (Decrease) in Other Regulatory Liabilities	1,097,029
16	(Less) Allowance for Other Funds Used During Construction	10,039,643
17	(Less) Undistributed Earnings from Subsidiary Companies	(6,346,800)
18	Other:Current Assets	(40,466,799)
19	Deferred Debits and Credits	78,738,286
20	Amortization of Leased Property	31,401,707
21		
22	Net Cash Provided by (Used in) Operating Activities (Total of lines 2 thru 21)	$1,220,456,953
23		
24	Cash Flows from Investment Activities:	
25	Construction and Acquisition of Plant (Including Land):	
26	Gross Additions to Utility Plant (less nuclear fuel)	(411,124,343)
27	Gross Additions to Nuclear Fuel	(67,630,040)
28	Gross Additions to Common Utility Plant	(25,741,550)
29	Gross Additions to Nonutility Plant	(1,340,554)
30	(Less) Allowance for Other Funds Used During Construction	10,039,643
31	Other:Non-utility Plant	732,538
32	Other Investments and Special Funds	(54,895,835)
33		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	($549,960,141)
35		
36	Acquisition of Other Noncurrent Assets (d)	
37	Proceeds from Disposal of Noncurrent Assets (d)	30,519,598
38	Cost of Removal	(60,815,864)
39	Investments in and Advances to Assoc. and Subsidiary Companies	(109,228,911)
40	Contributions and Advances from Assoc. and Subsidiary Companies	
41	Disposition of Investments in (and Advances to)	
42	Associated and Subsidiary Companies	
43		
44	Purchase of Investment Securities (a)	
45	Proceeds from Sales of Investment Securities (a)	

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

STATEMENT OF CASH FLOWS (Continued)

4. Investing Activities
Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed on pages 122-123.
Do not include on this statement the dollar amount of leases capitalized per US of A General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost on pages 122-123.

5. Codes used:
(a) Net proceeds or payments.
(b) Bonds,debentures and other long term debt.
(c) Include commercial paper.
(d) Identify separately such items as investments, fixed assets, intangibles, etc.

6. Enter on pages 122-123 clarifications and explanations.

Line No.	Description (See Instruction No. 5 for Explanation of Codes) (a)	Amounts (b)
46	Loans Made or Purchased	
47	Collections on Loans	
48		
49	Net (Increase) Decrease in Receivables	
50	Net (Increase) Decrease in Inventory	
51	Net (Increase) Decrease in Allowances Held for Speculation	
52	Net Increase (Decrease) in Payables and Accrued Expenses	
53	Other:	
54		
55		
56	Net Cash Provided by (Used in) Investing Activities	
57	(Total of lines 34 thru 55)	($689,485,318)
58		
59	Cash Flows from Financing Activities:	
60	Proceeds from Issuance of:	
61	Long - Term Debt (b)	43,704,098
62	Preferred Stock	0
63	Common Stock	11,301,443
64	Other: Change in Unamortized Premium/Discount	3,293,885
65	Issuance Expenses 275,149; LTIP Issuances 2,027,737	(2,302,886)
66	Net Increase in Short - Term Debt (c)	287,500,000
67	Other:	
68		
69		
70	Cash Provided by Outside Sources (Total of lines 61 thru 69)	$343,496,540
71		
72	Payments for Retirement of:	
73	Long - term Debt (b)	(427,462,500)
74	Preferred Stock	
75	Common Stock	
76	Other:	
77		
78	Net Decrease in Short-Term Debt (c)	
79	Capital Lease Payments	(31,401,707)
80	Dividends on Preferred Stock	(21,041,873)
81	Dividends on Common Stock	(390,526,931)
82	Net Cash provided by (Used in) Financing Activities	
83	(Total of lines 70 thru 81)	($526,936,471)
84		
85	Net Increase (Decrease) in Cash and Cash Equivalents	
86	(Total of lines 22, 57,and 83)	$4,035,164
87		
88	Cash and Cash Equivalents at Beginning of Year	17,171,879
89		
90	Cash and Cash Equivalents at End of Year	21,207,043

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.

2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility.Give also a brief explanation of any dividends in arrears on cumulative preferred stock.

3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.

4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.

5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.

6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK

SEE PAGE 123 FOR REQUIRED INFORMATION

NOTES TO FINANCIAL STATEMENTS (Continued)

1. Significant Accounting Policies

General

The consolidated financial statements of PECO Energy Company (Company) include the accounts of its utility subsidiary companies, all of which are wholly owned. Accounting policies are in accordance with those prescribed by the regulatory authorities having jurisdiction, principally the Pennsylvania Public Utility Commission (PUC) and the Federal Energy Regulatory Commission (FERC). The Company has unconsolidated non-utility subsidiaries which are not material. The unconsolidated subsidiaries are accounted for under the equity method.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Estimates are used in the Company's accounting for unbilled revenue, the allowance for uncollectible accounts, fuel adjustment clauses, depreciation and amortization, taxes, reserves for contingencies, employee benefits, certain fair value and recoverability determinations, and nuclear outage costs, among others.

Accounting for the Effects of Regulation

The Company follows the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," requiring the Company to record the financial statement effects of the rate regulation to which the Company is currently subject. If a separable portion of the Company's business no longer meets the provisions of SFAS No. 71,the Company would be required to eliminate the financial statement effects of regulation for that portion (see note 3).

Revenues

Electric and gas revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, the Company accrues an estimate for the unbilled amount of energy delivered or services provided to customers (see note 7).

Fuel and Energy Cost Adjustment Clauses

The Company's classes of service historically have been subject to fuel adjustment clauses designed to recover or refund the differences between the actual cost of fuel, energy interchange, purchased power and gas, and the amounts of such costs included in base rates. Differences between the amounts billed to customers and the actual costs recoverable

were deferred and recovered or refunded in future periods by means of prospective adjustments to rates. Generally, such rates were adjusted every twelve months.

In response to a Company proposal requesting the elimination of the Energy Cost Adjustment (ECA), the PUC approved the roll-in of energy costs into the base rates charged to the Company's electric customers. Effective December 31, 1996, the Company's classes of electric service are no longer subject to the ECA.

The Company's PUC-established Purchased Gas Cost Adjustment (PGC) which allows for the recovery of the difference between actual purchased gas costs and the amounts of such costs included in the base rates charged to the Company's natural gas customers will continue to be in effect subsequent to January 1, 1997.

Nuclear Fuel

The cost of nuclear fuel is capitalized and charged to fuel expense on the unit of production method. Estimated costs of nuclear fuel disposal are charged to fuel expense as the related fuel is consumed. The Company's share of nuclear fuel at Peach Bottom Atomic Power Station (Peach Bottom) and Salem Generating Station (Salem) is accounted for as a capital lease. Nuclear fuel at Limerick Generating Station (Limerick) is owned.

Depreciation and Decommissioning

The annual provision for depreciation is provided over the estimated service lives of plant on the straight-line method. Annual depreciation provisions for financial reporting purposes, expressed as a percentage of average depreciable utility plant in service, were approximately 2.90% in 1996, 2.80% in 1995 and 2.77% in 1994. See note 3 for information concerning the change in 1996 to depreciation and amortization.

The Company's share of the 1990 estimated costs for decommissioning nuclear generating stations currently included in electric base rates is being charged to operations over the expected service life of the related plant. The amounts recovered from customers are deposited in trust accounts and invested for funding of future costs. These amounts, and realized investment earnings thereon, are credited to accumulated depreciation (see note 4).

Income Taxes

The Company uses an asset and liability approach for financial accounting and reporting of income taxes. The effects of the Alternative Minimum Tax (AMT) are normalized. Investment tax credits are deferred and amortized to income over the estimated useful life of the related utility plant (see note 13).

Allowance for Funds Used During Construction (AFUDC)

AFUDC is the cost, during the period of construction, of debt and

equity funds used to finance construction projects. AFUDC is recorded as a charge to Construction Work in Progress, and the credits are to Interest Charges for the cost of borrowed funds and to Other Income and Deductions for the remainder as the allowance for other funds. The rates used for capitalizing AFUDC, which averaged 9.38% in 1996, 9.88% in 1995 and 7.74% in 1994, are computed under a method prescribed by regulatory authorities. AFUDC is not included in regular taxable income and the depreciation of capitalized AFUDC is not tax deductible.

Nuclear Outage Costs

Incremental nuclear maintenance and refueling outage costs are accrued over the unit operating cycle. For each unit, an accrual for incremental nuclear maintenance and refueling outage expense is estimated based upon the latest planned outage schedule and estimated costs for the outage. Differences between the accrued and actual expense for the outage are recorded when such differences are known.

Capitalized Software Costs

Software projects which exceed $5 million are capitalized. At December 31, 1996 and 1995, capitalized software costs totaled $78 million and $65 million (net of $29 million and $19 million accumulated amortization), respectively. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, not to exceed ten years.

Gains and Losses on Reacquired Debt

Gains and losses on reacquired debt are deferred and amortized to interest expense over the period approved for rate-making purposes.

Impairment of Long-Lived Assets

Effective January 1, 1996, under SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," long-lived assets are subject to periodic analysis for impairment. No loss from impairment has been recorded in 1996.

Reclassifications

Certain prior-year amounts have been reclassified for comparative purposes. These reclassifications had no effect on net income or common shareholders' equity.

2. Nature of Operations and Segment Information

The Company is an operating utility which provides electric and gas service to the public in southeastern Pennsylvania. The total area served by the Company covers 2,107 square miles. Electric service is supplied to an area of 1,972 square miles with a population of 3.6 million, including 1.6 million in the City of Philadelphia. Approximately 94% of the retail electric service area and 64% of retail

NOTES TO FINANCIAL STATEMENTS (Continued)

kilowatthour sales are in the suburbs around Philadelphia, and 6% of the retail service area and 36% of such sales are in the City of Philadelphia. Natural gas service is supplied to a 1,475-square-mile area of southeastern Pennsylvania adjacent to Philadelphia with a population of 1.9 million.

For the Years Ended December 31,	1996	1995	1994
		Thousands of Dollars	
Electric Operations			
Operating revenues:			
Residential	$ 1,370,158	$ 1,379,046	$ 1,371,237
Small commercial and industrial	748,561	730,220	710,028
Large commercial and industrial	1,098,307	1,135,550	1,149,193
Other	140,133	136,988	136,002
(Decrease)/increase in unbilled	(25,950)	42,580	(11,130)
Service territory	3,331,209	3,424,384	3,355,330
Interchange sales	25,991	17,488	23,017
Sales to other utilities	497,636	333,454	246,450
Total operating revenues	3,854,836	3,775,326	3,624,797
Operating expenses, excl. depr.	2,560,669	2,405,876	2,429,452
Depreciation	462,315	430,993	415,854
Operating income	$ 831,852	$ 938,457	$ 779,491
Utility plant additions	$ 447,105	$ 435,400	$ 457,728
Gas Operations			
Operating revenues:			
Residential	$ 15,716	$ 15,482	$ 16,048
House heating	249,507	235,456	237,397
Commercial and industrial	132,822	125,631	128,077
Other	11,462	5,382	20,168
(Decrease)/increase in unbilled	(4,250)	6,540	(3,140)
Subtotal	405,257	388,491	398,550
Other revenues (including trans. for customers)	23,557	22,339	17,285
Total operating revenues	428,814	410,830	415,835
Operating expenses, excl. depr.	328,585	319,127	339,529
Depreciation	26,686	26,261	26,247
Operating income	$ 73,543	$ 65,442	$ 50,059
Utility plant additions	$ 68,394	$ 63,192	$ 67,090
Identifiable Assets(*) at Dec. 31,			
Electric	$ 10,287,444	$ 10,408,105	$ 10,410,461
Gas	858,471	785,881	768,279
Nonallocable assets	4,114,704	4,114,519	4,243,410
Total assets	$ 15,260,619	$ 15,308,505	$ 15,422,150

(*) Includes utility plant less accumulated depreciation, inventories and allocated common utility property.

3. Rate Matters

Competition Act

The recently enacted electricity generation customer choice and competition Act(Competition Act) provides for the restructuring of the electric industry in Pennsylvania, including retail competition for generation beginning in 1999. At that date, the Company expects it will no longer meet the criteria of SFAS No.71 for the retail generation portion of its operations. The Competition Act requires the unbundling of electric services into separate generation, transmission and distribution services with open retail competition for generation. Electric distribution and transmission services will remain regulated by the PUC. The Competition Act requires utilities to submit to the PUC restructuring plans, including their stranded costs which will result from competition. Stranded costs include regulatory assets (see note 22), nuclear decommissioning costs and long-term purchased power commitments, for which full recovery is allowed, and other costs including investment in generating plants, spent fuel disposal, retirement costs and reorganization costs, for which an opportunity for recovery is allowed in an amount determined by the PUC as just and reasonable. These costs, after mitigation by the utility, are to be recovered and collected from distribution customers for up to nine years (or for an alternative period determined by the PUC for good cause shown). During that period, the utility is subject to a rate cap providing that total charges to customers cannot exceed rates in place as of December 31, 1996, subject to certain exceptions.

The Company estimates that its stranded costs resulting from retail generation competition at December 31, 1998 will be $7.1 billion. This estimate includes $3.9 billion of generating assets, $560 million of unfunded and as yet unrecorded decommissioning expenses and $2.6 billion of regulatory assets. On January 22, 1997, the Company filed an Application with the PUC seeking to recover $3.6 billion of its stranded costs and to securitize that recovery through the issuance by a third party assignee of $3.9 billion of Transition Bonds. The Company intends to seek recovery of the remaining $3.5 billion of its stranded costs in the Company's restructuring filing mandated by the Competition Act. To the extent the Company is not ultimately permitted by the PUC to recover its retail electric stranded costs, this amount could result in a charge against earnings. However, as of December 31, 1996, there is no impairment of its generation assets under SFAS No. 121, and given the stranded cost recovery provisions of the Competition Act, the Company believes that it will be given the opportunity for full recovery of its regulatory assets.

Under the Competition Act, the Company is required to use the proceeds it receives from any securitization of the recovery of stranded assets principally to reduce qualified stranded costs and related capitalization. In the Application, the Company proposes using the

proceeds it receives resulting from the issuance of the Transition Bonds to pay estimated transaction and use of proceeds costs of $277 million, to settle deferred fuel balances of $240 million and to reduce capitalization by approximately $3.4 billion. The capitalization reduction is expected to be proportionate to the Company's current capitalization.

Limerick

Under its electric tariffs, the Company is recovering $285 million of deferred Limerick costs representing carrying charges and depreciation associated with 50% of Limerick common facilities. These costs are included in base rates and are being recovered over a nine year period beginning October 1, 1996. The Company is also recovering $137 million of Limerick Unit No. 1 costs over a ten-year period without a return on investment. At December 31, 1996, the unrecovered portion of these balances were $228 and $46 million, respectively.

Under its electric tariffs and ECA, the Company was allowed to retain for shareholders any proceeds above the average energy cost for sales of 399 megawatts (MW) of near-term excess capacity and/or associated energy. In addition, beginning April 1994, the Company became entitled to share in the benefits which result from the operation of both Limerick Units No. 1 and No. 2 through the retention of 16.5% of the energy savings, subject to certain limits. During 1996, 1995 and 1994, the Company recorded as revenue net of fuel costs $82, $79 and $68 million, respectively, as a result of the sale of the 399 MW of capacity and/or associated energy and the Company's share of Limerick energy savings.

Pursuant to a PUC Declaratory Order issued in 1990, the Company deferred certain operating and maintenance expenses, depreciation and accrued carrying charges on its capital investment in Limerick Unit No. 2 and 50% of Limerick common facilities. At December 31, 1996 and 1995, such costs included in Deferred Limerick Costs totaled $88 and $91 million, respectively. These costs are included in base rates and are being recovered over a nine year period beginning October 1, 1996.

Declaratory Accounting Order

Pursuant to a PUC Declaratory Order, effective October 1, 1996, the Company increased depreciation and amortization on assets associated with Limerick by $100 million per year and decreased depreciation and amortization on other Company assets by $10 million per year, for a net increase in depreciation and amortization of $90 million per year.

Recovery of Non-Pension Postretirement Benefits Costs

Effective January 1995, in accordance with a PUC Joint Petition, the Company increased electric base rates by $25 million per year to recover the increased costs, including the annual amortization of the transition obligation (over 18 years) deferred in 1994 and 1993, associated with the implementation of SFAS No.106, "Employers'

Accounting for Postretirement Benefits Other Than Pensions,"(see note 6). Subsequent to January 1, 1995, retail electric non-pension postretirement benefits expense in excess of the amount allowed to be recovered under the Joint Petition may not be deferred for future rate recovery. During 1996 and 1995, the Company deposited $46.5 and $59.6 million, respectively, in trust accounts to fund its retail electric non-pension postretirement benefits costs. These costs include amounts charged to operating expense or capitalized on and after January 1, 1995.

In accordance with a December 1994 PUC approved accounting order, the Company is recognizing $2.8 million in non-pension postretirement benefits costs annually associated with gas utility operations. During 1996 and 1995, the Company deposited $2.9 and $3.8 million, respectively, in trust accounts to fund its gas non-pension postretirement benefits costs.

Energy Cost Adjustment

Through December 31, 1996, the Company was subject to a PUC-established electric ECA which, in addition to reconciling fuel costs and revenues, incorporated a nuclear performance standard which allowed for financial bonuses or penalties depending on whether the Company's system nuclear capacity factor exceeded or fell below a specified range. For the years ended December 31, 1996, 1995 and 1994, the Company recorded bonuses of $22, $13 and $14 million, respectively.

4. Commitments and Contingencies

Capital Commitments

Total construction program expenditures primarily for utility plant are estimated to be $560 million for 1997 and $1,225 million for the period 1998 to 2000. Construction expenditure estimates are reviewed and revised periodically to reflect changes in economic conditions and other appropriate factors. Certain facilities under construction and to be constructed may require permits and licenses which the Company has no assurance will be granted. Additionally, for the period 1997 through 2000, the Company plans to invest approximately $200-$300 million in other new ventures which includes telecommunications activities.

The Company's operations have in the past and may in the future require substantial capital expenditures in order to comply with environmental laws.

Nuclear Insurance

The Price-Anderson Act currently limits the liability of nuclear reactor owners to $8.9 billion for claims that could arise from a single incident. The limit is subject to change to account for the effects of inflation and changes in the number of licensed reactors. The Company carries the maximum available commercial insurance of $200 million and the remaining $8.7 billion is provided through mandatory participation

in a financial protection pool. Under the Price-Anderson Act, all nuclear reactor licensees can be assessed up to $79 million per reactor per incident, payable at no more than $10 million per reactor per incident per year. This assessment is subject to inflation and state premium taxes. In addition, Congress could impose revenue raising measures on the nuclear industry to pay claims.

The Company carries property damage, decontamination and premature decommissioning insurance in the amount of its $2.75 billion proportionate share for each station loss resulting from damage to its nuclear plants. In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund which the Company is required by the Nuclear Regulatory Commission (NRC) to maintain to provide for decommissioning the facility. The Company is unable to predict the timing of the availability of insurance proceeds to the Company for the Company's bondholders, and the amount of such proceeds which would be available. Under the terms of the various insurance agreements, the Company could be assessed up to $31 million for losses incurred at any plant insured by the insurance companies. The Company is self-insured to the extent that any losses may exceed the amount of insurance maintained. Any such losses, if not recovered through the ratemaking process, could have a material adverse effect on the Company's financial condition and results of operations.

The Company is a member of an industry mutual insurance company which provides replacement power cost insurance in the event of a major accidental outage at a nuclear station. The premium for this coverage is subject to assessment for adverse loss experience. The Company's maximum share of any assessment is $13 million per year.

Nuclear Decommissioning and Spent Fuel Storage

The Company's 1990 estimate of its nuclear facilities' decommissioning cost of $643 million is being collected through electric base rates over the life of each generating unit. Under current rates, the Company collects and expenses approximately $20 million annually from customers. The expense is accounted for as a component of depreciation expense and accumulated depreciation. At December 31, 1996 and 1995, $256 and $216 million, respectively, was included in accumulated depreciation. In order to fund future decommissioning costs, at December 31, 1996 and 1995, the Company held $266 and $223 million, respectively, in trust accounts which are included as an Investment in the Company's Consolidated Balance Sheet and include both net unrealized and realized gains. Net unrealized gains of $26 and $19 million were recognized as a Deferred Credit in the Company's Consolidated Balance Sheet at December 31, 1996 and 1995, respectively. The Company recognized net realized gains of $10, $9 and $7 million as Other Income in the Company's Consolidated Statement of Income for the years ended December 31, 1996, 1995 and 1994 respectively. The most recent estimate

NOTES TO FINANCIAL STATEMENTS (Continued)

of the Company's share of the cost to decommission its nuclear units is $1.4 billion in 1995 dollars. The Company has included the unfunded and as yet unrecorded portion of the decommissioning trust fund estimate in its January 22, 1997 application with the PUC.

In an exposure draft issued in 1996, the Financial Accounting Standards Board (FASB) proposed changes in the accounting for closure and removal costs of production facilities, including the recognition, measurement and classification of decommissioning costs for nuclear generating stations. The FASB is currently considering expanding the scope of the Exposure Draft to include closure or removal liabilities that are incurred at any time in the operating life of the long-lived asset. The FASB plans to issue either a final Statement or a revised Exposure Draft in the second quarter of 1997. If current electric utility industry accounting practices for decommissioning are changed, annual provisions for decommissioning could increase and the estimated cost for decommissioning could be recorded as a liability rather than as accumulated depreciation with recognition of an increase in the cost of the related asset.

Under the Nuclear Waste Policy Act of 1982 (NWPA), the U.S. Department of Energy (DOE) is required to begin taking possession of all spent nuclear fuel generated by the Company's nuclear units for long-term storage by no later than 1998. Based on recent public pronouncements, it is not likely that a permanent disposal site will be available for the industry before 2015, at the earliest. In reaction to statements from the DOE that it was not legally obligated to begin to accept spent fuel in 1998, a group of utilities and state government agencies filed a lawsuit against the DOE which resulted in a decision by the United States Court of Appeals for the District of Columbia (D.C. Court of Appeals) in July 1996 that the DOE had an unequivocal obligation to begin to accept spent fuel in 1998. In accordance with the NWPA, the Company pays the DOE one mill ($.001) per kilowatthour of net nuclear generation for the cost of nuclear fuel disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. Because of inaction by the DOE in response to the D.C. Court of Appeals finding of the DOE's obligation to begin receiving spent fuel in 1998, a group of thirty-six utility companies, including the Company, and forty-six state agencies, filed suit against the DOE on January 31, 1997 seeking authorization to suspend further payments to the U.S. government under the NWPA and to deposit such payments into an escrow account until such time as the DOE takes effective action to meet its 1998 obligations. Legislation introduced in Congress in January 1997 would authorize construction of a temporary storage facility which could accept spent nuclear fuel from utilities soon after 1998. In addition, the DOE is exploring other options to address delays in the waste acceptance schedule.

Peach bottom and Limerick have on-site facilities with the capacity to store spent nuclear fuel discharged from the units through the early 2000s. Life-of-plant storage capacity could be provided by the

construction of on-site dry cask storage facilities. Salem has on-site facilities with spent fuel storage capacity through 2008 for Unit No. 1 and 2012 for Unit No. 2. Public Service Electric and Gas Company (PSE&G) is the operator of Salem, which is 42.59% owned by the Company.

The Company is currently recovering in rates costs for nuclear decommissioning and decontamination and spent fuel storage. The Company believes that the ultimate costs of decommissioning and decontamination and spent fuel disposal will continue to be recoverable, although such recovery is not assured.

Energy Purchases

In the ordinary course of business, the Company enters into commitments to buy and sell power. As of December 31,1996, the Company had long-term aggreements to purchase from unaffiliated utilities, primarily in 1997, energy associated with 2,200 MW of capacity. During 1996, purchases under long-term agreements resulted in expenditures of $44 million. At December 31, 1996, these purchases result in commitments of approximately $259 million for 1997, $48 million for 1998, $51 million for 1999, $52 million for 2000 and $50 million for 2001. These purchases will be utilized through a combination of sales to jurisdictional customers primarily to compensate for the Salem shutdown, long-term sales to other utilities and open market sales.

Environmental Issues

The Company's operations have in the past and may in the future require substantial capital expenditures in order to comply with environmental laws. Additionally, under federal and state environmental laws, the Company is generally liable for the costs of remediating environmental contamination of property now or formerly owned by the Company and of property contaminated by hazardous substances generated by the Company. The Company owns or leases a number of real estate parcels, including parcels on which its operations or the operations of others may have resulted in contamination by substances which are considered hazardous under environmental laws. The Company is currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

The Company has identified 27 sites where former manufactured gas plant (MGP) activities have or may have resulted in actual site contamination. The Company is presently engaged in performing various levels of activities at these sites, including initial evaluation to determine the existence and nature of the contamination, detailed evaluation to determine the extent of the contamination and the necessity and possible methods of remediation, and implementation of remediation. Eight of the sites are under some degree of active study or remediation.

As of December 31, 1996 and 1995, the Company had accrued $28 and $27 million, respectively, for environmental investigation and

remediation costs, including $16 and $13 million, respectively, for MGP investigation and remediation, that currently can be reasonably estimated. The Company cannot predict whether it will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Company, environmental agencies or others, or whether all such costs will be recoverable from third parties.

Shutdown of Salem Generating Station

PSE&G removed Salem Units No. 1 and No. 2 from service in the second quarter of 1995 and informed the NRC at that time that it had determined to keep the Salem units shut down pending review and resolution of certain equipment and management issues and NRC agreement that each unit is sufficiently prepared to restart. PSE&G estimates the projected restart of Unit No. 2 to occur in the second quarter of 1997 and of Unit No. 1 to occur in the summer of 1997. It is the Company's belief that the earliest that Unit No. 1 will return to service is late in the third quarter of 1997. For the years ended December 31, 1996 and 1995, the Company had incurred and expensed approximately $149 million and $50 million of replacement power and maintenance costs, respectively.

Litigation

The Company is involved in various litigation matters, the ultimate outcome of such matters, while uncertain, is not expected to have a material adverse effect on the Company's financial condition or results of operations.

5. Retirement Benefits

The Company and its subsidiaries have a non-contributory trusteed retirement plan applicable to all regular employees. The benefits are based primarily upon employees' years of service and average earnings prior to retirement. The Company's funding policy is to contribute, at a minimum, amounts sufficient to meet the Employee Retirement Income Security Act requirements. Approximately 80%, 74% and 85% of pension costs were charged to operations in 1996, 1995 and 1994, respectively, and the remainder, associated with construction labor, to the cost of new utility plant.

Pension costs for 1996, 1995 and 1994 included the following components:

	1996	1995	1994
	Thousands of Dollars		
Service cost benefits earned during the period	$ 27,627	$ 19,710	$ 33,403
Interest cost on projected			

NOTES TO FINANCIAL STATEMENTS (Continued)

benefit obligation	145,570	147,261	136,690
Actual return on plan assets	(320,247)	(456,057)	12,946
Amortization of transition asset	(4,538)	(4,538)	(4,538)
Amortization and deferral	154,402	300,214	(161,955)
Net pension cost	$ 2,814	$ 6,590	$ 16,546

The changes in net periodic pension costs in 1996, 1995 and 1994 were as follows:

	1996	1995	1994
	Thousands of Dollars		
Change in number, characteristics and salary levels of participants and net actuarial gain	$ (12,893)	$ 1,486	$ (6,004)
Change in plan provisions	--	(8,305)	(1,777)
Change in actuarial assumptions	9,117	(3,136)	(959)
Net change	$ (3,776)	$ (9,955)	$ (8,740)

Plan assets consist principally of common stock, U.S. government obligations and other fixed income instruments. In determining pension costs, the assumed long-term rate of return on assets was 9.5% for 1996, 1995 and 1994.

The weighted-average discount rate used in determining the actuarial present value of the projected benefit obligation was 7.75% at December 31, 1996, 7.25% at December 31, 1995 and 8.25% at December 31, 1994. The average rate of increase in future compensation levels ranged from 4% to 6% at December 31, 1996 and 1995, and from 4.25% to 6.25% at December 31, 1994.

Prior service cost is amortized on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan.

The funded status of the plan at December 31, 1996 and 1995 is summarized as follows:

	1996	1995
	Thousands of Dollars	
Actuarial present value of accumulated plan benefit obligations:		
Vested benefit obligation	$(1,657,098)	$(1,746,685)
Accumulated benefit obligation	(1,742,116)	(1,838,661)
Projected benefit obligation for services rendered to date	$(1,982,915)	$(2,097,300)
Plan assets at fair value	2,302,935	2,088,950
Funded status	320,020	(8,350)
Unrecognized transition asset	(40,251)	(44,789)

Unrecognized prior service costs	92,682	68,223
Unrecognized net gain	(588,013)	(265,472)
Pension liability recognized on the balance sheet	$ (215,562)	$ (250,388)

6. Non-Pension Postretirement Benefits

The Company provides certain health care and life insurance benefits for retired employees. Company employees become eligible for these benefits if they retire from the Company with ten years of service. These benefits and similar benefits for active employees are provided by an insurance company whose premiums are based upon the benefits paid during the year.

The transition obligation, which represents the previously unrecognized accumulated non-pension postretirement benefit obligation, is being amortized on a straight-line basis over an allowed 20-year period. As a result of voluntary retirement and separation programs in 1994, the Company accelerated recognition of $177 million of its non-pension postretirement benefits obligation (see note 21).

The transition obligation was determined by application of the terms of medical, dental and life insurance plans, including the effects of established maximums on covered costs, together with relevant actuarial assumptions and health care cost trend rates, which are projected to range from 8% in 1997 to 5% in 2002. The effect of a 1% annual increase in these assumed cost trend rates would increase the accumulated postretirement benefit obligation by $68 million and the annual service and interest costs by $8 million.

Total costs for all plans amounted to $71 million in 1996 and 1995 and $81 million in 1994.

The net periodic benefits costs for 1996 and 1995 included the following components:

	1996	1995	1994
	Thousands of Dollars		
Service cost benefits earned during the period	$ 11,855	$ 8,681	$ 17,056
Interest cost on projected benefit obligation	48,524	48,641	41,196
Amortization of transition asset	14,882	14,882	22,659
Actual return on plan assets	(13,257)	(2,075)	--
Deferred asset gain	9,320	1,359	--
Net postretirement benefits costs	$ 71,324	$ 71,488	$ 80,911

Plan assets consist principally of common stock, U.S. government obligations and other fixed income instruments. In determining non-pension postretirement benefits costs, the assumed long-term rate of return on assets was 8% for 1996, 1995 and 1994.

The weighted-average discount rate used in determining the actuarial present value of the projected benefit obligation was 7.50% as of January 1, 1996, 8.50% as of January 1, 1995 and 7.25% at January 1, 1994. The average rate of increase in future compensation levels ranged from 4% to 6% at December 31, 1996 and 1995, and from 4.25% to 6.25% at December 31, 1994.

Prior service cost is amortized on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan.

The funded status of the plan at December 31, 1996 and 1995 is summarized as follows:

	1996	1995
	Thousands of Dollars	
Accumulated postretirement benefit obligation:		
Retirees	$ 609,206	$ 628,804
Fully eligible active plan participants	4,509	4,199
Other active plan participants	48,986	41,863
Total	662,701	674,866
Plan assets at fair value	(126,661)	(66,735)
Accumulated postretirement benefit obligation in excess of plan assets	536,040	608,131
Unrecognized transition obligation	(238,108)	(252,990)
Unrecognized net gain	(17,126)	(28,890)
Accrued postretirement benefits cost recognized on the balance sheet	$ 315,058	$ 326,251

Measurement of the accumulated postretirement benefits obligation was based on a 7.75% and 7.5% assumed discount rate as of December 31, 1996 and 1995, respectively.

For the regulatory treatment of non-pension postretirement benefits costs, see note 3.

7. Accounts Receivable

Accounts receivable at December 31, 1996 and 1995 included unbilled operating revenues of $117 and $148 million, respectively. Accounts receivable at December 31, 1996 and 1995 were net of an allowance for uncollectible accounts of $24 and $21 million, respectively.

The Company is party to an agreement with a financial institution under which it sold with limited recourse an undivided interest, adjusted daily, in up to $425 million of designated accounts receivable until November 14, 2000. At December 31, 1996 and 1995, the Company had sold a $425 million interest in accounts receivable. The Company retains the servicing responsibility for these receivables.

By terms of this agreement, under certain circumstances, a portion of deferred Limerick costs may be included in the pool of eligible receivables. At December 31, 1996, $23 million of deferred Limerick costs were included in the pool of eligible receivables.

8. Common Stock

At December 31, 1996 and 1995, common stock without par value consisted of 500,000,000 shares authorized and 222,542,087 and 222,172,216 shares outstanding, respectively. At December 31, 1996, there were 5,800,841 shares reserved for issuance under the dividend reinvestment and stock purchase plan.

Long-Term Incentive Plan (LTIP)

The Company maintains an LTIP for certain full-time salaried employees of the Company. The types of long-term incentive awards which may be granted under the LTIP are non-qualified options to purchase shares of the Company's common stock, dividend equivalents and shares of restricted common stock. The Company has adopted the disclosure-only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," but applies Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" and related interpretations in accounting for the LTIP. If the Company had elected to account for the LTIP based on SFAS No. 123, earnings applicable to common stock and earnings per average common share would have been changed to the pro forma amounts as indicated below:

	1996	1995
	Thousands of Dollars	
Earnings applicable to common stock		
As reported	$499,169	$586,515
Pro forma	$497,887	$585,063
Earnings per average common share (Dollars)		
As reported	$ 2.24	$ 2.64
Pro forma	$ 2.24	$ 2.64

Options granted under the LTIP become exercisable on the anniversary of the date of grant and all options expire 10 years from the date of the grant. Information with respect to the LTIP at December 31, 1996 and changes for the three years then ended, is as follows:

Shs 1996	Weighted Average Exercise Price (per share) 1996	Shs 1995	Weighted Average Exercise Price (per share) 1995	Shs 1994	Weighted Average Exercise Price (per share) 1994

Bal. @ Jan. 1	2,591,765	$ 26.16	2,651,397	$ 26.73	1,961,882	$ 25.12
Options granted	786,500	28.12	850,700	26.46	909,000	30.13
Options exercised	(369,871)	25.07	(561,232)	23.91	(90,885)	22.91
Options cancelled	(47,200)	29.36	(349,100)	35.57	128,600)	28.87
Bal. @ Dec. 31	2,961,194	26.68	2,591,765	26.16	2,651,397	26.73
Exercisable At Dec. 31	2,192,694	26.17	1,813,565	25.91	1,865,397	25.21
Weighted average fair value of options granted during year		$ 2.78		$ 2.91		$ --

The fair value of each option is estimated on the date of the grant using the Black-Scholes option-pricing model.

The following weighted average assumptions were used for grants in 1996: dividend yield of 6.2%, expected volatility of 16.6%, risk-free interest rate of 5.5%, and an expected life of five years. The following weighted average assumptions were used for grants in 1995: dividend yield of 6.2%, expected volatility of 15.3%, risk-free interest rate of 6.9%, and an expected life of five years.

At December 31, 1996, the option groups outstanding based on ranges of exercise prices is as follows:

	Options Outstdng			Options Exercisable	
Range of Exercise Prices	No. Outstndng	Weighted-Average Remaining Contract. Life (Years)	Weighted-Average Exercise Price	No. Exercisable	Weighted-Average Exercise Price
$15.75 - $20.00	117,594	3.86	$ 18.43	117,594	$ 18.43
$20.01 - $25.00	155,500	4.75	22.70	125,500	22.37
$25.01 - $30.00	2,675,900	7.63	27.23	1,941,400	26.86
$30.01 - $50.00	12,200	7.55	37.18	8,200	30.93
Total	2,961,194			2,192,694	

9. Preferred and Preference Stock

At December 31, 1996 and 1995, Series Preference Stock consisted of 100,000,000 shares authorized, of which no shares were outstanding. At December 31, 1996 and 1995, cumulative Preferred Stock, no par value, consisted of 15,000,000 shares authorized.

	Current Redemption Price(a)	Shares Outstndng 1996	Shares Outstndng 1995	Amount Thousands of $ 1996	Amount Thousands of $ 1995

NOTES TO FINANCIAL STATEMENTS (Continued)

Series (without mandatory redemption)					
$4.68	104.00	150,000	150,000	$ 15,000	$ 15,000
$4.40	112.50	274,720	274,720	27,472	27,472
$4.30	102.00	150,000	150,000	15,000	15,000
$3.80	106.00	300,000	300,000	30,000	30,000
$7.96(b)	(c)	618,954	618,954	61,895	61,895
$7.48	(d)	500,000	500,000	50,000	50,000
Subtotal		1,993,674	1,993,674	199,367	199,367
Series (with mandatory redemption)					
$6.12	(e)	927,000	927,000	92,700	92,700
Total preferred stock		2,920,674	2,920,674	292,067	$ 292,067

(a) Redeemable, at the option of the Company, at the indicated dollar amounts per share, plus accrued dividends.
(b) Ownership of this series of preferred stock is evidenced by depositary receipts, each representing one-fourth of a share of preferred stock.
(c) None of the shares of this series are subject to redemption prior to October 1, 1997.
(d) None of the shares of this series are subject to redemption prior to April 1, 2003.
(e) There are no annual sinking fund requirements in the period 1997-1998. Annual sinking fund requirements in 1999 are $18,540,000. None of the shares of this series are subject to redemption prior to August 1, 1999.

10. Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership (COMRPS)

At December 31, 1996 and 1995, PECO Energy Capital, L.P. (Partnership), a Delaware limited partnership of which a wholly owned subsidiary of the Company is the sole general partner, had outstanding two series of cumulative COMRPS, each with a liquidation value of $25 per security. Each series is supported by the Company's deferrable interest subordinated debentures, held by the Partnership, which bear interest at rates equal to the distribution rates on the securities. The interest paid by the Company on the debentures is included in Interest Charges in the Consolidated Statements of Income and is deductible for income tax purposes.

			Shares Outstndng		Amount Thousands of Dollars	
@ Dec. 31,	Due	Dist. Rate	1996	1995	1996	1995
Series A	2043	9.00%	8,850,000	8,850,000	$ 221,250	$ 221,250

B (a)	2025	8.72%	3,124,183	3,124,183	80,932	81,032
Total			11,974,183	11,974,183	$ 302,182	$ 302,282

(a) Ownership of this series is evidenced by Trust Receipts, each representing a 8.72% COMRPS, Series B, representing limited partnership interests. The Trust Receipts were issued by PECO Energy Capital Trust I, the sole assets of which are 8.72% COMRPS, Series B. Each holder of Trust Receipts is entitled to withdraw the corresponding number of 8.72% COMRPS, Series B from the Trust in exchange for the Trust Receipts so held.

11. Long-Term Debt

At December 31,	Series	Due	1996	1995
			Thousands of Dollars	
First and refunding mortgage bonds (a)	6 1/8%	1997	$ 75,000	$ 75,000
	5 3/8%	1998	225,000	225,000
	7 1/2%-9 1/4%	1999	325,000	325,000
	5 5/8%-7 3/8%	2001	330,000	330,000
	6 3/8%-8%	2002-2006	1,025,000	1,025,000
	10 1/4%	2007-2011	44,688	48,750
	(b)	2012-2016	154,200	188,200
	6 7/10%-7 3/5%	2017-2021	277,590	277,590
	6 5/8%-8 3/4%	2022-2024	1,329,540	1,329,540
Total			3,786,018	3,824,080
Notes payable - banks			--	167,000
Term loan agreements	(c)	1997	175,000	350,000
Pollution control notes	(d)	1997-2034	212,705	169,005
Medium-term notes	(e)	1997-2005	74,400	121,800
Unamortized debt discount and premium, net			(29,306)	(32,599)
Total long-term debt			4,218,817	4,599,286
Due within one year (f)			283,303	401,003
Long-term debt included in capitalization (g)			$ 3,935,514	$ 4,198,283

(a) Utility plant is subject to the lien of the Company's mortgage.
(b) Floating rates, which were an average annual interest rate of 3.532% at December 31, 1996.
(c)The average annual rate in 1996 was 5.94%. The Company also has a $400 million revolving credit and term loan agreement with a group of banks which terminates in 2001. There is an annual commitment fee of 0.125% on the unused amount. There was no debt outstanding under this agreement at December 31, 1996.
(d) Floating rates, which were an average annual interest rate of 3.620% at December 31, 1996.
(e) Medium-term notes collateralized by mortgage bonds. The average

annual interest rate was 8.465% at December 31, 1996.
(f) Long-term debt maturities, including mandatory sinking fund requirements, in the period 1997-2001 are as follows: 1997 - $283,303,000; 1998 -$241,463,000; 1999 - $359,063,000; 2000 - $4,063,000; 2001 - $334,063,000.
(g) The annualized interest on long-term debt at December 31, 1996, was $292 million, of which $274 million was associated with mortgage bonds and $18 million was associated with other long-term debt.

12. Short-Term Debt

	1996	1995	1994
		Thousands of Dollars	
Average borrowings	$ 198,090	$ 17,560	$ 130,539
Average interest rates, computed on daily basis	5.64%	6.25%	4.03%
Maximum borrowings outstanding	$ 369,500	$182,000	$ 418,600
Average interest rates, at December 31	6.90%	--	6.73%

The Company has a $300 million commercial paper program which is supported by the $400 million revolving credit agreement (see note 11); at December 31, 1996, $200 million was outstanding. In 1996, $87.5 million of a term loan agreement with a group of banks was refinanced with a single bank as short-term debt under a 364-day term loan facility; at December 31, 1996, $87.5 million was outstanding. At December 31, 1996, the Company had formal and informal lines of credit with banks aggregating $275 million. No short-term debt was outstanding against these lines at that date.

13. Income Taxes

Income tax expense is comprised of the following components:

For the Years Ended Dec. 31,	1996	1995	1994
		Thousands of Dollars	
Included in operating income:			
Federal			
Current	$ 126,702	$ 170,042	$ 164,472
Deferred	156,129	159,970	(2,691)
Investment tax credit, net	(15,979)	(21,679)	28,006
State			
Current	63,447	72,177	77,754
Deferred	12,806	16,387	(33,508)
Subtotal	343,105	396,897	234,033
Included in other income and deductions:			

NOTES TO FINANCIAL STATEMENTS (Continued)

Federal			
Current	(231)	20,754	1,989
Deferred	(1,565)	7,556	9,722
State			
Current	(608)	6,909	409
Deferred	(600)	(399)	3,171
Subtotal	(3,004)	34,820	15,291
Total	$ 340,101	$ 431,717	$ 249,324

The total income tax provisions differed from amounts computed by applying the federal statutory tax rate to income as shown below:

	1996	1995	1994
	Thousands of Dollars		
Net Income	$ 517,205	$ 609,732	$ 426,713
Total income tax provisions	340,101	431,717	249,324
Income before income taxes	$ 857,306	$ 1,041,449	$ 676,037
Income taxes on above at federal statutory rate at 35%	$ 300,057	$ 364,507	$ 236,613
Increase (decrease) due to:			
Depreciation timing differences not normalized	7,924	14,127	12,767
Limerick plant disallowances and phase-in plan	(651)	(736)	(530)
AFUDC	(6,981)	(9,467)	(7,759)
State income taxes, net of federal income tax benefit	48,779	61,799	31,086
Amortization of investment tax credit	(15,979)	(13,604)	(14,570)
Prior period income taxes	(1,707)	1,791	(14,524)
Other, net	8,659	13,300	6,241
Total income tax provisions	$ 340,101	$ 431,717	$ 249,324
Effective Income Tax rate	39.7%	41.5%	36.9%

Provisions for deferred income taxes consist of the tax effects of the following temporary differences:

	1996	1995	1994
	Thousands of Dollars		
Depreciation and amortization	$ 42,385	$ 32,287	$ 85,772
Deferred energy costs	27,374	30,073	13,777
Retirement and separation programs	19,746	15,733	(82,008)
Incremental nuclear maintenance and refueling outage costs	2,440	8,079	(2,751)
Uncollectible accounts	(2,805)	(1,991)	(23,096)
Reacquired debt	(9,578)	(3,266)	(12,954)

NOTES TO FINANCIAL STATEMENTS (Continued)

Unrecovered revenue	3,910	(5)	(2,239)
Environmental clean-up costs	(714)	2,433	(3,949)
Obsolete inventory	5,829	6,362	(6,192)
Limerick plant disallowances and phase-in plan	(747)	2,507	12,894
AMT credits	83,010	91,399	--
Other	(4,080)	(97)	(2,560)
Total	$ 166,770	$ 183,514	$ (23,306)

The tax effect of temporary differences which gives rise to the Company's net deferred tax liability as of December 31, 1996 and 1995 are as follows:

	Liability or (Asset) 1996	1995
	Millions of Dollars	
Nature of temporary difference		
Plant basis difference	$ 3,796	$ 3,797
Deferred investment tax credit	336	351
Deferred debt refinancing cost	120	130
Other, net	(168)	(249)
Deferred income taxes (net) on the balance sheet	$ 4,084	$ 4,029

The net deferred tax liability shown above as of December 31, 1996 and 1995 is comprised of $4,347 and $4,401 million of deferred tax liabilities, and $263 and $372 million of deferred tax assets, respectively.

In accordance with SFAS No. 71, the Company has recorded a recoverable deferred income tax asset of $2,322 million and $2,420 million at December 31, 1996 and 1995, respectively (see note 22). These recoverable deferred income taxes include the deferred tax effects associated principally with liberalized depreciation accounted for in accordance with the ratemaking policies of the PUC, as well as the revenue impacts thereon, and assume recovery of these costs in future rates.

The Internal Revenue Service (IRS) has completed and settled its examinations of the Company's federal income tax returns through 1986. The 1987 through 1990 federal income tax returns have been examined and the IRS subsequently issued an assessment that the Company has appealed. The Company does not expect the ultimate resolution of the assessment and its appeal to have a material effect upon the Company's financial condition or results of operations. The years 1991 through 1993 are currently being examined by the IRS.

Investment tax credits and other general business credits were fully utilized for tax purposes at December 31, 1994 and reduced federal income taxes currently payable by $43 million in 1994. The AMT credit was fully utilized for tax purposes at December 31, 1996, and reduced

federal income taxes currently payable by $71 million in 1996.

14. Taxes, Other Than Income - Operating

For the Years Ended December 31,	1996	1995	1994
	Thousands of Dollars		
Gross receipts	$160,246	$165,172	$160,704
Capital stock	41,972	42,444	39,957
Real estate	69,185	71,600	77,571
Payroll	27,585	30,109	31,556
Other	558	4,746	1,901
Total	$299,546	$314,071	$311,689

15. Leases

Leased property included in utility plant at December 31, was as follows:

	1996	1995
	Thousands of Dollars	
Nuclear fuel	$ 527,116	$ 494,051
Electric plant	2,069	2,076
Gross leased property	529,185	496,127
Accumulated amortization	(347,097)	(315,702)
Net leased property	$ 182,088	$ 180,425

The nuclear fuel obligation is amortized as the fuel is consumed. Amortization of leased property totaled $31, $43 and $62 million for the years ended December 31, 1996, 1995 and 1994, respectively. Other operating expenses included interest on capital lease obligations of $9, $10 and $7 million in 1996, 1995 and 1994, respectively.

Minimum future lease payments as of December 31, 1996 were:

For the Year Ending Dec. 31,	Capital Leases	Operating Leases	Total
	Thousands of Dollars		
1997	$ 49,804	$ 47,919	$ 97,723
1998	54,595	44,541	99,136
1999	45,751	42,339	88,090
2000	22,267	41,534	63,801
2001	20,305	40,632	60,937
Remaining years	18,598	554,412	573,010
Total minimum future lease payments	$ 211,320	$ 771,377	$ 982,697
Imputed interest (rates ranging from 6.5% to 17.0%)	(29,232)		

NOTES TO FINANCIAL STATEMENTS (Continued)

Present value of net minimum future lease payments $ 182,088

Rental expense under operating leases totaled $74, $115 and $101 million in 1996, 1995 and 1994, respectively.

16. Jointly Owned Electric Utility Plant

The Company's ownership interests in jointly owned electric utility plant at December 31, 1996 were as follows:

	Production Plants				Trans. & Other Plant
Operator	P. Bottom PECO Energy Co.	Salem PSE&G	Keystone GPU Gen. Corp.	Conemaugh GPU Gen. Corp.	Various Companies
Partic. Interest	42.49%	42.59%	20.99%	20.72%	21% to 43%
Co.'s share (000's)					
Utility plant	$ 754,271	$1,234,771	$ 108,144	$ 165,713	$ 87,623
Accum. Depr.	326,778	432,959	59,231	67,216	30,475
CWIP	49,441	164,122	8,956	22,529	1,164

The Company's participating interests are financed with Company funds and, when placed in service, all operations are accounted for as if such participating interests were wholly owned facilities.

17. Cash and Cash Equivalents

For purposes of the Statements of Cash Flows, the Company considers all highly liquid debt instruments purchased with a maturity of three months or less to be cash equivalents. The following disclosures supplement the accompanying Statements of Cash Flows:

	1996	1995	1994
	Thousands of Dollars		
Cash paid during the year:			
Interest (net of amount capitalized)	$415,063	$449,664	$437,096
Income taxes (net of refunds)	251,554	257,677	205,316
Noncash investing and financing:			
Capital lease obligations incurred	33,063	48,760	41,763

18. Investments

At December 31,	1996	1995
	Thousands of Dollars	

Trust accounts for decommissioning nuclear plants	$266,270	$222,655
Telecommunications ventures	79,833	21,500
Energy services and other ventures	44,023	40,779
Nonutility property	26,349	26,816
Other deposits	11,255	132
Emission allowances	2,480	6,347
Gas exploration and development joint ventures	2,364	219
Total	$432,574	$318,448

19. Financial Instruments

Fair values of financial instruments, including liabilities, are estimated based on quoted market prices for the same or similar issues. The carrying amounts and fair values of the Company's financial instruments as of December 31, 1996 and 1995 were as follows:

Thousands of Dollars	1996		1995	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and temporary cash investments	$ 29,235	$ 29,235	$ 20,602	$ 20,602
Long-term debt (incl. amounts due within one year)	4,218,817	4,239,357	4,599,286	4,773,700
Trust accounts for decom. nuclear plants	266,270	266,270	222,655	222,655

Financial instruments which potentially subject the Company to concentrations of credit risk consist principally of temporary cash investments and customer accounts receivable. The Company places its temporary cash investments with high-credit, quality financial institutions. At times, such investments may be in excess of the Federal Deposit Insurance Corporation limit. Concentrations of credit risk with respect to customer accounts receivable are limited due to the Company's large number of customers and their dispersion across many industries.

20. Other Income

Nuclear Fuel Agreement with Long Island Power Authority (LIPA)

In 1994, the Company recognized $26 million as Other Income in accordance with a 1993 agreement with LIPA and other parties to accept slightly irradiated nuclear fuel from Shoreham Nuclear Power Station.

Sale of Subsidiary

On June 19, 1995, the Company completed the sale of Conowingo Power Company (COPCO) to Delmarva Power & Light Company (Delmarva) for $150 million. The transaction also included a ten-year contract for the

Company to sell power to Delmarva. The Company's gain of $59 million ($27 million net of taxes) on the sale was recorded in the second quarter of 1995.

21. Voluntary Retirement and Separation Programs

The Company incurred a one-time, pre-tax charge of $254 million ($145 million net of taxes) in the third quarter of 1994 as a result of voluntary retirement and separation programs approved by the Company's Board of Directors in April 1994. Pursuant to these programs 1,474 employees elected to retire and 1,008 employees elected to voluntarily separate from the Company. The retirements and separations took place in stages through December 31, 1995. As a result of the programs, in 1994 the Company accelerated recognition of $177 million of its non-pension postretirement benefits obligation. The Company recorded a corresponding regulatory asset and is recovering this amount in rates as a component of non-pension postretirement benefits expense. The recognition of the $177 million of non-pension postretirement benefits obligation and corresponding regulatory asset did not impact earnings.

22. Regulatory Assets and Liabilities

At December 31, 1996 and 1995, the Company had deferred the following regulatory assets on the Consolidated Balance Sheet:

	1996	1995
	Millions of Dollars	
Recoverable deferred income taxes (see note 13)	$2,322	$2,420
Deferred Limerick costs (see note 3)	362	390
Loss on reacquired debt	284	309
Compensated absences	38	33
Deferred energy costs (see note 3)	122	56
Non-pension postretirement benefits (see note 3)	233	248
Total	$3,361	$3,456

23. Quarterly Data (Unaudited)

The data shown below include all adjustments which the Company considers necessary for a fair presentation of such amounts:

	Oper. Revenues		Oper. Income		Net Income	
Millions of $	1996	1995	1996	1995	1996	1995
Quarter ended						
March 31	$1,171	$1,059	$ 253	$ 257	$ 150	$ 152
June 30	989	959	196	233	99	154
September 30	1,110	1,125	249	292	150	184

NOTES TO FINANCIAL STATEMENTS (Continued)

December 31	1,014	1,044	208	222	118	120

	Earnings Applicable to Common Stock		Average Shares Outstanding		Earnings Per Average Share	
Millions of $	1996	1995	1996	1995	1996	1995
Quarter ended						
March 31	$146	$146	222.4	221.7	$ 0.65	$ 0.66
June 30	94	148	222.5	221.8	0.43	0.67
September 30	145	178	222.5	221.9	0.65	0.80
December 31	114	115	222.5	221.9	0.51	0.52

The decrease in 1996 third quarter results was primarily due to the lower electric revenues from less favorable weather conditions, higher customer expenses and higher costs related to the Salem outage.

1995 second quarter results include a pre-tax gain of $59 million ($27 million net of taxes), or $0.12 per share, as a result of the sale of COPCO (see note 20).

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Line No.	Item (a)	Total (b)	Electric (c)
1	UTILITY PLANT		
2	In Service		
3	Plant in Service (Classified)	$13,809,341,036	$12,721,019,669
4	Property Under Capital Leases	498,090	498,090
5	Plant Purchased or Sold		
6	Completed Construction not Classified	1,001,270,346	767,319,056
7	Experimental Plant Unclassified	0	
8	TOTAL (Enter Total of lines 3 thru 7)	$14,811,109,472	$13,488,836,815
9	Leased to Others	0	
10	Held for Future Use	6,362,710	6,063,899
11	Construction Work in Progress	648,692,609	494,819,628
12	Acquisition Adjustments	0	
13	TOTAL Utility Plant (Enter total of lines 8 thru 12)	$15,466,164,791	$13,989,720,342
14	Accum. Prov. for Depr., Amort., & Depl.	5,010,636,480	4,648,676,398
15	Net Utility Plant (Enter Total of line 13 less 14)	$10,455,528,311	$9,341,043,944
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION		
17	In Service:		
18	Depreciation	4,977,807,196	4,635,123,377
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights	0	
20	Amort. of Underground Storage Land and Land Rights		
21	Amort. of Other Utility Plant	32,829,284	13,553,021
22	TOTAL In Service (Enter Total of lines 18 thru 21)	$5,010,636,480	$4,648,676,398
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort. of Plant Aquisition Adj.		
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22,26,30,31 and 32)	$5,010,636,480	$4,648,676,398

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other(Specify) (e)	Other(Specify) (f)	Other(Specify) (g)	Common (h)	Line No.
					1
					2
$875,353,867				$212,967,500	3
					4
					5
130,150,703				103,800,587	6
					7
$1,005,504,570				$316,768,087	8
					9
2,259				296,552	10
12,654,025				141,218,956	11
					12
$1,018,160,854	0	0	0	$458,283,595	13
259,015,351				102,944,731	14
$759,145,503	0	0	0	$355,338,864	15
					16
					17
259,015,351	0			83,668,468	18
					19
					20
				19,276,263	21
$259,015,351	0		0	$102,944,731	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
$259,015,351	0		0	$102,944,731	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [x] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

NUCLEAR FUEL MATERIALS (Accounts 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.

2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes During Year: Additions (c)
1	Nuclear Fuel in process of Refinement, Conversion, Enrichment & Fabrication (120.1)		
2	Fabrication	0	
3	Nuclear Materials	64,897,482	53,498,643
4	Allowance for Funds Used during Construction	807,222	164,327
5	(Other Overhead Construction Costs)		
6	SUBTOTAL (Enter Total of lines 2 thru 5)	$65,704,704	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	0	123,666
9	In Reactor (120.3)	315,336,843	40,016,674
10	SUBTOTAL (Enter Total of lines 8 thru 9)	$315,336,843	
11	Spent Nuclear Fuel (120.4)	414,910,272	24,145,129
12	Nuclear Fuel Under Capital Leases (120.6)	179,858,636	33,065,166
13	(Less) Accum. Prov. for Amortization of Nuclear Fuel Assemblies (120.5)	604,867,680	
14	TOTAL Nuclear Fuel Stock (Enter Total lines 6, 10, 11, and 12 less line 13)	$370,942,775	
15	Estimated net Salvage Value of Nuclear Materials in line 9	0	
16	Estimated net Salvage Value of Nuclear Materials in line 11	0	
17	Estimated net Salvage Value of Nuclear Materials in Chemical Processing	0	
18	Nuclear Materials held for Sale (157)	0	
19	Uranium	0	
20	Plutonium	0	
21	Other	0	
22	TOTAL Nuclear Materials held for Sale Enter Total of lines 19, 20, and 21	0	

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

NUCLEAR FUEL MATERIALS (Accounts 120.1 through 120.6 and 157)(Continued)

Changes During the Year		Balance End of Year	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)	(f)	
			1
		0	2
	* 49,704,660	68,691,465	3
	* 681,520	290,029	4
		0	5
		$68,981,494	6
			7
		123,666	8
		355,353,517	9
		$355,477,183	10
0		439,055,401	11
31,333,927		181,589,875	12
(59,067,776)		663,935,456	13
		* $381,168,497	14
		0	15
		0	16
		0	17
		0	18
		0	19
		0	20
		0	21
		0	22

< Page 203 Line 3 Column e >

Transfer of Nuclear fuel in process of refinement to Nuclear fuel in Reactor account 120.3.

< Page 203 Line 4 Column e >

Transfer of Nuclear fuel in process of refinement to Nuclear fuel in Reactor account 120.3.

< Page 203 Line 14 Column f >

Peach Bottom
Nuclear fuel for Peach Bottom Units #2 and #3 is leased from the Mid-Atlantic Fuel Company. PECO Energy Company's cost incurred under the rental agreement for Units #2 and #3 was $31,333,927 for Nuclear Fuel Burn-up, and $4,863,138 for Financing Charges. At December 31, 1996, Unit #2 contained 53,964,264 grams of uranium with an enrichment of 2.28% and Unit #3 contained 53,958,348 grams of uranium with an enrichment of 1.64%.

Salem
Nuclear fuel for Salem Units #1 and #2 is leased from the Philadelphia Salem Fuel Corp. PECO Energy Company's cost incurred under the rental agreement for Units #1 and #2 was $0 for Nuclear Fuel Burn-up, and $3,717,285 for Financing Charges. At December 31, 1996, Unit #1 contained 36,659,206 grams of uranium with an enrichment of 1.89% and Unit #2 contained 37,136,554 grams of uranium with an enrichment of 2.55% (units did not generate in 1996).

Limerick
Nuclear fuel for Limerick Units #1 and #2 is not obtained under a leasing agreement. At December 31, 1996 Unit #1 contained 128,707,968 grams of uranium with an enrichment of 2.09%, and Unit #2 contained 128,582,597 grams of uranium with an enrichment of 1.31%.

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ELECTRIC PLANT IN SERVICE (Accounts 101,102,103,and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.

2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.

3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.

4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.

5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column(d) reversals of tentative distributions of prior year of unclassified retirements. Show in a footnote the account distributions of these tentative classifications in columns (c) and (d), including the

Line No.	Account (a)	Balance at Beginning of Year (b)	Addition (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	162,934	
4	(303) Miscellaneous Intangible Plant	55,224,806	30,051,411
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	$55,387,740	$30,051,411
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	5,506,904	
9	(311) Structures and Improvements	222,097,391	316,595
10	(312) Boiler Plant Equipment	784,672,680	8,872,996
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	218,713,188	2,096,775
13	(315) Accessory Electric Equipment	91,512,824	1,183,405
14	(316) Misc. Power Plant Equipment	18,756,661	69,223
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	$1,341,259,648	$12,538,994
16	B. Nuclear Production Plant		
17	(320) Land and Land Rights	11,406,160	3,600,412
18	(321) Structures and Improvements	1,941,442,682	981,433
19	(322) Reactor Plant Equipment	4,463,356,742	24,079,233
20	(323) Turbo generator Units	863,933,411	817,411
21	(324) Accessory Electric Equipment	1,104,411,983	3,886,597
22	(325) Misc. Power Plant Equipment	397,683,971	2,658,423
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)	$8,782,234,949	$36,023,509
24	C. Hydraulic Production Plant		
25	(330) Land and Land Rights	1,420,823	
26	(331) Structures and Improvements	17,477,824	59,333
27	(332) Reservoirs, Dams, and Waterways	34,439,961	
28	(333) Water Wheels, Turbines, and Generators	27,829,947	(74,728)
29	(334) Accessory Electric Equipment	10,612,664	
30	(335) Misc. Power Plant Equipment	2,186,762	22,856
31	(336) Roads, Railroads, and Bridges	997,676	
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)	$94,965,657	$7,461
33	D. Other Production Plant		
34	(340) Land and Land Rights	841,219	
35	(341) Structures and Improvements	5,119,523	
36	(342) Fuel Holders, Products, and Accessories	23,924,084	
37	(343) Prime Movers		
38	(344) Generators	94,756,690	7,794
39	(345) Accessory Electric Equipment	12,933,260	(7,794)

ELECTRIC PLANT IN SERVICE (Accounts 101,102,103,and 106)(Continued)

reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column(f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 399,state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			0	(301)	2
			162,934	(302)	3
			85,276,217	(303)	4
			$85,439,151		5
					6
					7
			5,506,904	(310)	8
1,516,515			220,897,471	(311)	9
1,637,277			791,908,399	(312)	10
			0	(313)	11
1,197,098			219,612,865	(314)	12
1,016,071			91,680,158	(315)	13
51,989			18,773,895	(316)	14
$5,418,950			$1,348,379,692		15
					16
			15,006,572	(320)	17
1,490,011			1,940,934,104	(321)	18
6,315,820			4,481,120,155	(322)	19
236,051			864,514,771	(323)	20
2,573,415			1,105,725,165	(324)	21
324,075			400,018,319	(325)	22
$10,939,372			$8,807,319,086		23
					24
			1,420,823	(330)	25
			17,537,157	(331)	26
			34,439,961	(332)	27
404,333			27,350,886	(333)	28
19,164			10,593,500	(334)	29
6,008			2,203,610	(335)	30
			997,676	(336)	31
$429,505			$94,543,613		32
					33
			841,219	(340)	34
11,033			5,108,490	(341)	35
			23,924,084	(342)	36
			0	(343)	37
22,044	(60,843)		94,681,597	(344)	38
			12,925,466	(345)	39

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ELECTRIC PLANT IN SERVICE (Accounts 101,102,103,and 106)(Continued)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
40	(346) Misc. Power Plant Equipment	$2,443,208	
41	TOTAL Other Prod. Plant (Enter Total of lines 34 thru 40)	$140,017,984	0
42	TOTAL Prod. Plant (Enter Total of lines 15, 23, 32, and 41)	$10,358,478,238	$48,569,964
43	3. TRANSMISSION PLANT		
44	(350) Land and Land Rights	51,976,079	6,811,913
45	(352) Structures and Improvements	21,013,196	14,334
46	(353) Station Equipment	318,548,207	2,822,681
47	(354) Towers and Fixtures	227,238,032	714,481
48	(355) Poles and Fixtures	3,145,702	
49	(356) Overhead Conductors and Devices	115,589,491	6,553
50	(357) Underground Conduit	7,382,039	(1,384,928)
51	(358) Underground Conductors and Devices	55,158,411	8,195,676
52	(359) Roads and Trails	2,054,612	
53	TOTAL Transmission Plant (Enter Total of lines 44 thru 52)	$802,105,769	$17,180,710
54	4. DISTRIBUTION PLANT		
55	(360) Land and Land Rights	31,732,030	1,393,518
56	(361) Structures and Improvements	47,599,132	(65,084)
57	(362) Station Equipment	489,638,779	2,802,491
58	(363) Storage Battery Equipment		
59	(364) Poles, Towers, and Fixtures	249,879,400	17,800,353
60	(365) Overhead Conductors and Devices	383,963,801	38,436,866
61	(366) Underground Conduit	198,522,298	4,983,932
62	(367) Underground Conductors and Devices	424,462,377	15,465,024
63	(368) Line Transfomers	279,108,486	8,957,348
64	(369) Services	228,325,075	3,451,453
65	(370) Meters	177,525,972	15,363,358
66	(371) Installations on Customer Premises	350,215	
67	(372) Leased Property on Customer Premises		
68	(373) Street Lighting and Signal Systems	17,613,587	1,519,888
69	TOTAL Distribution Plant (Enter Total of lines 55 thru 68)	$2,528,721,152	$110,109,147
70	5. GENERAL PLANT		
71	(389) Land and Land Rights	2,109,929	374,504
72	(390) Structures and Improvements	35,476,512	581,733
73	(391) Office Furniture and Equipment	15,713,595	682,123
74	(392) Transportation Equipment	129,813	(129,813)
75	(393) Stores Equipment	43,382	
76	(394) Tools, Shop and Garage Equipment	8,356,918	470,605
77	(395) Laboratory Equipment	19,143,019	452,168
78	(396) Power Operated Equipment		
79	(397) Communication Equipment	8,679,794	390,573
80	(398) Miscellaneous Equipment	1,514,121	658
81	SUBTOTAL (Enter Total of lines 71 thru 80)	$91,167,083	$2,822,551
82	(399) Other Tangible Property	(527,419,708)	
83	TOTAL General Plant (Enter Total of lines 81 and 82)	($436,252,625)	$2,822,551
84	TOTAL (Accounts 101 and 106) (lines 5,15,23,32,41,53,69,83)	$13,308,440,274	$208,733,783
85	(102) Electric Plant Purchased (See Instr. 8)		
86	(Less) (102) Electric Plant Sold (See Instr. 8)		
87	(103) Experimental Plant Unclassified		
88	TOTAL Electric Plant in Service (Enter Total of lines 84 thru 87)	$13,308,440,274	$208,733,783

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ELECTRIC PLANT IN SERVICE (Accounts 101,102,103,and 106)(Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of year (g)		Line No.
			$2,443,208	(346)	40
$33,077	($60,843)	0	$139,924,064		41
$16,820,904	($60,843)	0	$10,390,166,455		42
					43
			58,787,992	(350)	44
3,870			21,023,660	(352)	45
523,640		53,323	320,900,571	(353)	46
			227,952,513	(354)	47
			3,145,702	(355)	48
599			115,595,445	(356)	49
			5,997,111	(357)	50
291,417			63,062,670	(358)	51
			2,054,612	(359)	52
$819,526		$53,323	$818,520,276		53
					54
		397,792	33,523,340	(360)	55
81,442			47,452,606	(361)	56
2,946,281	(505,027)	(53,323)	488,936,639	(362)	57
			0	(363)	58
636,442			267,043,311	(364)	59
1,700,807		(1,801)	420,698,059	(365)	60
686,673			202,819,557	(366)	61
3,811,658		835	436,116,578	(367)	62
10,722			288,055,112	(368)	63
867,005		1,801	230,911,324	(369)	64
			192,889,330	(370)	65
			350,215	(371)	66
			0	(372)	67
260,280		(835)	18,872,360	(373)	68
$11,001,310	($505,027)	$344,469	$2,627,668,431		69
					70
			2,484,433	(389)	71
			36,058,245	(390)	72
25,514			16,370,204	(391)	73
			0	(392)	74
			43,382	(393)	75
			8,827,523	(394)	76
			19,595,187	(395)	77
			0	(396)	78
			9,070,367	(397)	79
			1,514,779	(398)	80
$25,514			$93,964,120		81
			(527,419,708)	(399)	82
$25,514			($433,455,588)		83
$28,667,254	($565,870)	$397,792	$13,488,338,725		84
				(102)	85
					86
				(103)	87
$28,667,254	($565,870)	$397,792	$13,488,338,725		88

Name of Respondent PECO Energy Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.

2. For property having an original cost of $ 250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Expansion of Chester Generating Station	01/01/1967	01/01/2012	$3,559,189
3	Proposed Peach Bottom-Limerick 500 KV Line	01/01/1972	01/01/2012	683,515
4	Proposed Llanerch Sub Site (5123)	01/01/1975	01/01/1997	443,333
5				
6	26 Properties - having original cost			
7	less than $250,000			1,377,862
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	TOTAL			$6,063,899

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

CONSTRUCTION WORK IN PROGRESS--ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).

2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).

3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)
1	PRODUCTION PLANT	
2	LGS(9346-0) Site Support Building Renovation	2,524,411
3	LGS Common Admin. Bldg	8,601,185
4	PB Replace 2A Recirc Pump Shaft	2,220,677
5	Renovations Admin Bldg "B" MOD 5303	1,843,544
6	Renovations Admin Bldg "A" MOD 5302	889,195
7	Office/Warehouse Complex MOD 5307	5,071,860
8	Salem #1 Spent Fuel Pool Re-Rack	2,929,018
9	Salem #1 Analog Feedwater Control System	4,470,231
10	Salem #2 Analog Feedwater Control System	2,956,560
11	Conemaugh #2 Flue Gas Desulfurization System	13,846,628
12	Eddy #1 IP/HP BFP Replacement (JWP) (M-1210)	8,068,654
13	LGS Common - Addition and Renovations to Tech Support Center 8013	1,978,573
14	LGS Common - Procurment and Installation of Furniture	973,748
15	PB Common - Upgrade Auxilliary Boilers	1,081,581
16	PB #2 Replace Recirc MG Sets w/ASD Incl Rpt MOD P00086	3,726,830
17	PB #3 Replace Recirc MG Sets w/ASD Incl Rpt MOD P00086	1,823,706
18	PB #2 Replace SRM/IRM with NUMAC System MOD 5395	1,654,746
19	PB #3 TIP System Upgrades MOD P0068	823,992
20	Salem Gen Station Replace R41 Radiation Monitors Unit 1	1,565,772
21	Salem Gen Station Replace R41 Radiation Monitors Unit 2	1,505,597
22	Salem Gen Station Switchgear Penetration Area Unit 2	1,328,707
23	Salem Gen Station Switchgear Penetration Areas Unit 1	1,615,473
24	Salem Gen Station Fuel Handling Spent Upgrade Unit 1	983,515
25	Salem Gen Station Repl Low Pressure MSR Bundle Unit 1	1,895,535
26	Salem Gen Station Feedwater Htr Replacement Unit 2	918,276
27	Cromby Unit 1 - Additions to Continuous Emiss. Mont. Sys.	1,251,284
28	Cromby Unit 2 - Install Continuous Emiss. Mont. Sys.	1,171,579
29	Eddy #1 - Replace Superpressure Turbine	2,964,909
30	Keystone Station - Wastewater Treatment Facility	1,068,174
31	Muddy Run - Replace P-50 Computer System	4,138,719
32	Richmond Gen Station - Construct new Storage Bldg	1,283,266
33	LGS Common - Digital Alarming Dosimeters	982,715
34	LGS - Cooling Tower Fill Replacement	4,928,084
35	Hydro Water Install P00391-2	1,813,305
36	LGS Purchase RX Tensioner Carousel	865,317
37	LGS Furniture for GML Renovation	1,067,484
38	PB Employee Parking Lot	1,236,669
39	PB - Condensate Demin. System Upgrades	1,142,408
40	Salem Generating Station - Unit 1 Replace P250 Computer	1,243,294
41	Salem Generating Station - Unit 2 Replace P250 Computer	1,778,715
42	Salem Generating Station - Replace Large Bore Pipe	1,525,846
43	TOTAL	

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

CONSTRUCTION WORK IN PROGRESS--ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).

2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).

3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)
1	PRODUCTION PLANT (Con't)	
2	Salem Generating Station - Small Bore Piping	1,760,581
3	Salem Generating Station - Unit 2 HVAC Aux. Bldg. Upgrade	772,671
4	Cromby Station #2 -L-0/L-1 Turb Blades	1,761,636
5	Eddy Unit #2 Nox Ract Installation	8,821,731
6	Eddy Unit #1 Nox Ract Installation	9,082,423
7	LGS - Hydrogenn Water Chemistry	1,683,419
8	LGS - Cooling Tower Fill Replacement	765,007
9	LGS Capital Replacement	1,526,430
10	PB-Non-MOD Capital Jobs	821,260
11	Conemaugh Gen Station Retentions	2,923,960
12	Cromby Unit #2 Rebuild Generator Rotor	1,126,376
13	Muddy Run Station Unit 5 & 6 Overhaul	9,133,811
14	Keystone - Turbine - Generator DEH Co System Retrofit Unit 1	823,523
15	Oregon Shop Building Renovations	1,672,240
16	Passport Project - PGG	814,029
17	Muddy Run Install 3&4 Runner	1,415,525
18	Muddy Run Install 1&2 Runner	2,314,186
19	Muddy Run - Replace Main Generator Cable	1,260,261
20	Muddy Run Install 7&8 Runner	3,272,835
21	Salem Main Construction Bill	15,319,065
22	Salem Gen Station - Comm Central Warehouse Facil - Art. Is. - Master Plan	7,354,602
23	Conemaugh - Acquire Water Flowage Rights East and Main Branches Perki	1,014,381
24	Peach Bottom #3 NUMAC Monitor System	815,463
25	Peach Bottom #2 Replace RFPT MCU's	935,095
26	Salem Unit #1 Fish Baskets CWTS	1,224,988
27	Salem #1 Replace Large Bore Head Pipe	1,951,115
28	Salem #2 Replace Large Bore Head Pipe	1,682,501
29	Salem Turbine Rotor Replacement	14,098,592
30	Salem #2 Replace Large Bore Header	1,631,419
31	Salem #1 Small Bore Piping	2,907,185
32	Salem #1 Replace Service Water Pumps	1,350,542
33	Salem #2 Replace Service Water Pumps	1,530,391
34	Salem Feedwater Flow Measure System	1,401,226
35	Salem #1 - Hagen Control	1,806,183
36	Salem #2 - Hagen Control	2,683,211
37	Salem Steam Generator	25,201,864
38	Salem Steeling Air/Turbo Boost	1,145,416
39	Salem Control Room Emergency Air Conditioner	5,628,964
40	Salem #1 Test Inspection	5,824,716
41	Salem #1 Site Preparation	4,633,094
42	Salem # 1 Remove and Replace	7,277,904
43	TOTAL	

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

CONSTRUCTION WORK IN PROGRESS--ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).

2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).

3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)
1	PRODUCTION PLANT (Con't)	
2	Salem #2 Licensing	5,664,110
3	Salem #1 Remove and Replace	2,048,006
4	Salem Control Room Improvements	771,926
5	Salem Replace 11C Feedwater Heater	874,909
6	Limerick Hydrogen Water Chemistry	941,836
7	Limerick Turbine Rotors Casing	7,719,962
8	Peach Bottom Condensate Demin. System Upgrades	1,267,787
9	Peach Bottom Unit 2 - Shroud Restraints	1,346,791
10	Peach Bottom Unit 1 Boiler Control Replacement	1,123,744
11	Peach Bottom T/G Non - TSI Vile Monitoring	754,082
12	Limerick Unit 1 New Air Backwash System	807,008
13	Limerick Unit 2 New Air Backwash System	868,110
14	Limerick Unit 2 Recorders Delete/Replacement	759,159
15	Limerick Unite 2 Additions to Turbine Bldg.	1,504,962
16	Chesterbrook Capital Tools & Equipment	835,984
17	Limerick Unit 1 - West Access	843,618
18	PB Plant Access w/Chem Lab	3,908,128
19	Minor Projects Grouped	80,120,318
20		
21	TRANSMISSION PLANT	
22	Static Wire - Limerick, Cromby, Audubon	2,616,683
23	Build a Middletown -Morton 230kv Line (TRH) (T-947)	10,002,834
24	Replace 3 Pumping Plants	787,904
25	Replace Pilot Wire Relaying	1,769,983
26	Minor Projects Grouped	3,157,820
27		
28	DISTRIBUTION PLANT	
29	Morton Conversion	4,914,407
30	Morton-New 230 - 13KV Substation	9,799,098
31	Newtown Sq. - Install 69-13KV Sub. (D-3191) (CMG)	5,843,968
32	Master - Install 230-13 KV Duplex (JEC) (D-0351)	1,376,024
33	Newlinville Reclosers	5,150,883
34	Royersford Area - New 230-34 KV Sub (JPM) (D-054)	1,007,102
35	Newtown Square Area - 69 KV Line and Substation	1,334,532
36	Buckingham Sub. - Install Second 230-34 KV Cuplex(FDP)	5,612,803
37	Peach Bottom North - Install 1-21 MVA 230 DV Trans	793,457
38	Chatham - New 230 -34KV Substation	3,346,197
39	Buckingham Project	3,972,369
40	R_S_R_ - Delchester	2,162,901
41		
42		
43	TOTAL	

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

CONSTRUCTION WORK IN PROGRESS--ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).

2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).

3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)
1	DISTRIBUTION PLANT (Con't)	
2	Power Delivery	4,719,528
3	Sun 69-13 KV Substation	5,412,261
4	Install Units at Ardmore Substation	901,775
5	North Wales RSR	1,392,775
6	130 - 52 Line Rebuild	1,204,860
7	ICP/MICP Capital Charges	8,662,048
8	Property Valuation	2,693,106
9	WMS Capital Accrual	4,675,914
10	Audubon Area - New 220-13KV Sub	6,627,571
11	Minor Projects Grouped	10,553,990
12		
13	RESIDENTIAL SALES	
14	Valley Forge Woods/Fernleigh 216 Singles & 106 Townhouses	946,573
15	Univ. of Penn Substation #3	2,174,800
16	Minor Projects Grouped	1,238,706
17		
18	INDUSTRIAL SALES	
19	Epsilon Products	932,302
20	Minor Projects Grouped	949,319
21		
22	STREET LIGHT IMPROVEMENTS	
23	Minor Projects Grouped	71,920
24		
25	MUNICIPAL IMPROVEMENTS	
26	Minor Projects Grouped	(8,507)
27		
28	GENERAL PLANT	
29	Energy Management System Replacement	789,104
30	Minor Projects Grouped	2,142,575
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	$494,819,628

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

CONSTRUCTION OVERHEADS-ELECTRIC

1. List in column (a) the kinds of overheads according to the titles used by the respondent. Charges for outside professional services for engineering fees and management or supervision fees capitalized should be shown as separate items.

2. On page 218 furnish information concerning construction overheads.

3. A respondent should not report "none" to the page if no overhead apportionments are made, but rather should explain on page 218 the accounting procedures, employed and the amounts of engineering, supervision and administrative costs, etc. which are directly charged to construction.

4. Enter on this page engineering, supervision, administrative, and allowance for funds used during construction, etc., which are first assigned to a blanket work order and then prorated to construction jobs.

Line No.	Description of Overhead (a)	Total Amount Charged for the Year (b)
1	Engineering & Supervision	$70,519,000
2	Allowance for Funds Used During Construction	17,752,000
3	Engineering Services	538,000
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	$88,809,000

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. For each construction overhead explain: (a) the nature and extent of work, etc. the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.

2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Electric Plant Instructions 3(17) of the U.S. of A.

3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

See Supplement Attachment.

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

For line 1(5), column (d) below, enter the rate granted in the last rate proceeding. If such is not available, use the average rate earned during the preceding three years.

1. Components of Formula (Derived from actual book balances and actual cost rates):

Line No.	Title (a)	Amount (b)	Capitalization Ratio (Percent) (c)	Cost Rate Percentage (d)
(1)	Average Short-Term Debt	S $198		
(2)	Short-Term Interest			s 5.61%
(3)	Long-Term Debt	D $168	47.40%	d 8.65%
(4)	Preferred Stock	P $21	6.10%	p 8.50%
(5)	Common Equity	C $164	46.50%	c 12.75%
(6)	Total Capitalization	$353	100%	
(7)	Average Construction Work in Progress Balance	W * $551		

2. Gross Rate for Borrowed Funds $s(\frac{S}{W}) + d(\frac{D}{D+P+C})(1 - \frac{S}{W})$ 4.77%

3. Rate for Other Funds $[1 - \frac{S}{W}][p(\frac{P}{D+P+C}) + c(\frac{C}{D+P+C})]$ 4.13%

4. Weighted Average Rate Actually Used for the Year:

a. Rate for Borrowed Funds - 4.49%

b. Rate for Other Funds - 4.66%

< Page 218 Line 7 Column b >

GENERAL DESCRIPTION OF OVERHEAD PROCEDURES

1.(A) Construction Overheads consist of the following:
"Engineering & Supervision" - expenditures for services and expenses of engineers, draftsmen and superintendents employed on construction work.
"Engineering Services" - Consulting fees for plans, designs preparation of estimates, supervision and inspection of construction work.
"Allowance for Funds Used During Construction" - Cost of money charged to construction.

1.(b)(f) All of the above are directly assigned to capital except a portion of "Engineering and Supervision". The unassignable is allocated to capital on basis of time studies prepared annually for the groups engaged in both construction and operations.

1.(c,d,e) The overheads assignable directly to capital are charged to a specific job as incurred. The remainder is distributed monthly to specific jobs, by department, on the basis of Company labor, contract labor and purchase orders charged to capital.

2.(a) Allowance for Funds Used during Construction - are applied to all construction work in progress except:
1. Amounts withheld from contractors or suppliers to ensure performance.
2. Property available for service immediately.
3. Jobs completed in less than one month.
4 CWIP allowed in Rate Base.

(b) The method employed in computing the allowance was to apply one-half of one month's portion of the rate to current month charges plus a full month's portion of the rate to the prior month's cumulative basis.

(c) The allowance computation period starts when the first month's charges are incurred and ends in the month the job is either in service or ready for service. On jobs exceeding $1,000,000 (estimated) interest is calculated to calendar "in-service date".

(d) The allowance for 1996 was computed at an average rate of 9.15 percent.

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.

2. Explain in a footnote any difference between the amount for book cost of plant retired, line 11, column (c), and that reported for electric plant in service, pages 204-207, column (d), excluding retirements of non-depreciable property.

3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and / or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.

4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	$4,246,616,708	$4,246,616,708		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	411,412,245	411,412,245		
4	(413) Exp. of Elec. Plt.Leas.to Others				
5	Transportation Expenses—Clearing				
6	Other Clearing Accounts	16,770,950	16,770,950		
7	Other Accounts (Specify):				
8					
9	Total Deprec. Prov. for Year (Enter Total of lines 3 thru 8)	$428,183,195	$428,183,195		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	(28,667,255)	(28,667,255)		
12	Cost of Removal	(11,791,298)	(11,791,298)		
13	Salvage (Credit)	782,027	782,027		
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	($39,676,526)	($39,676,526)		
15	Other Debit or Cr.Items (Describe):				
16					
17	Balance End of Year (Enter Total of lines 1, 9, 14, 15, and 16)	$4,635,123,377	$4,635,123,377		

Section B. Balances at End of Year According to Functional Classifications

18	Steam Production	798,892,911	798,892,911		
19	Nuclear Production	2,476,162,690	2,476,162,690		
20	Hydraulic Production-Conventional	0			
21	Hydraulic Production-Pumped Storage	42,873,026	42,873,026		
22	Other Production	124,687,530	124,687,530		
23	Transmission	333,324,464	333,324,464		
24	Distribution	830,849,617	830,849,617		
25	General	28,333,139	28,333,139		
26	TOTAL (Enter Total of lines 18 thru 25)	$4,635,123,377	$4,635,123,377		

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

NONUTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of non-utility property included in Account 121.

2. Designate with a double asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.

3. Furnish particulars (details) concerning sales, purchases, or transfers of Nonutility Property during the year.

4. List separately all property previously devoted to public service and give date of transfer to Account 121, Nonutility Property.

5. Minor Items (5% of the Balance at the End of the Year), for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service(line 44), or(2) other nonutility property (line 45).

Line No.	Description and Location (a)	Balance of Beginning of Year (b)	Purchases, Sales, Transfers, etc. (c)	Balance at End of Year (d)
1	NEVER IN PUBLIC SERVICE			
2	Land & Structures - Pottstown-Limerick Airport (9519)	2,516,285	71,443	2,587,728
3	Land - Prop. System Operation Site (9829)	1,644,342	(7,420)	1,636,922
4	Land & Structures - Bradford-Newlinville Line (9531)	1,439,144		1,439,144
5	Land & Struct. - Concord-Middletown Line,Delco (5002)	1,786,152	116,862	1,903,014
6	Land & Struct.Schuylkill Div Serv Bldg (9527)	1,301,571	10,507	1,312,078
7	Land & Struct.-Newtown Serv. Bldg Bucks Co (0378)	1,352,474	(640,812)	711,662
8	Land-Limerick Trans. Montgomery Co (9534)	1,076,041	(1,691)	1,074,350
9	Land -Prop Charleston Area Gen Sta (9803)	728,810		728,810
10	Land -Merrill Creek Reservoir, NJ (0002)	665,267		665,267
11	Land & Struct. -Elroy-Branchburg Transm Line (7517)	525,291		525,291
12	Land & Struct. -Plumstead Twnship Bucks Co (9503)	37,598		37,598
13	Land & Struct. -Fulton Nuclear Power St. York (0005)		356,571	356,571
14	Land -Packer Substation, Phil. (1025)	204,888		204,888
15	Land - Chichester Substation, Phila (0753)	195,226		195,226
16	Land & Struct. -Hendricks Island, Bucks Co (9526)	181,777	(17,378)	164,399
17	Land & Struct. -900 Pine St Darby Boro(9540)	178,517		178,517
18	Land & Struct. -Ivyland City Gate Sta(0630)	177,750	(88,906)	88,844
19	Land & Struct. -Welsh Rd,Lower Moreland(9524)	147,284		147,284
20	Land -Hartranft,Substa,Phil(9809)	144,649		144,649
21	Land -San Miguel, Colorado (9536)	143,729		143,729
22	Land -Bradshaw Reservoir Water Del. Syst. to Lim (0004)	133,120		133,120
23	Land & Struct. - Eddystone Gen. Sta (0006)	110,879		110,879
24	land -Tacony Substation, Phila (1113)	102,859		102,859
25	Land-Former R/W Eddystone - Phila. (9528)	102,778		102,778
26	Land -Overbrook Substation, Phila (1006)	101,033		101,033
27	Land & Struct. - Goshen Sub Site (3606)	364,835		364,835
28	Land & Towers Heaton - Woodbourne (7057)	3,501,666		3,501,666
29	Land - Peach Bottom Newlinville (7022)	146,313		146,313
30	Structures & Equip - Fairless Hills Station (0142)		329,471	329,471
31	Structures & Equip - Tullytown Station - (0141)		103,730	103,730
32	Structures & Equip - 401 City Ave., Mont. Cnty (0402)		368,453	368,453
33	Minor Items	3,201,492	(985,702)	2,215,790
34				
35	PREVIOUSLY IN PUBLIC SERVICE			
36	Land & Struct. - Elro-Hosensack(7518)	926,982		926,982
37	Land & Assoc. Equip.-Chester Sta. Delaware Co. (0008)	790,330		790,330
38	Coal Hand. Equip. - Schuylkill Sta, Phila (0001)	360,517		360,517
39	Land & Struct. - Former Federal Subst. (1002)	215,333		215,333
40	Land -Christian St. Serv. Bldg. (0373)	214,207		214,207
41	Land & Struct. - Elroy -Brandchberg Line (7517)	145,275		145,275
42				
43				
44	Minor Item Previously Devoted to Public Service			
45	Minor Items-Other Nonutility Property			
46	TOTAL			

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

NONUTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of nonutility property included in Account 121.

2. Designate with a double asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.

3. Furnish particulars (details) concerning sales, purchases, or transfers of Nonutility Property during the year.

4. List separately all property previously devoted to public service and give date of transfer to Account 121, Nonutility Property.

5. Minor Items (5% of the Balance at the End of the Year), for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service(line 44), or(2) other nonutility property (line 45).

Line No.	Description and Location (a)	Balance of Beginning of Year (b)	Purchases, Sales, Transfers, etc. (c)	Balance at End of Year (d)
1	PREVIOUSLY IN PUBLIC SERVICE (CON'T)			
2	Land -Muddy Run Pumped Storage(0019)	124,436		124,436
3	Land & Struct. - West Chester Serv Bldg(0359)	115,936		115,936
4	Storage Tank - Tilghman St. Gas Plant, Del. Co. (0626)	101,994		101,994
5	Land & Struct. -Chester Distr. Office(0465)	1,062,049		1,062,049
6	Peach Bottom -Keeney,PA Line to DE Line(7930)	1,284,737	(47,288)	1,237,449
7	Land & Struct. Elkton Service Bldg (7930)	993,542		993,542
8	Equipment-Conowingo Power Company	184,932		184,932
9	Land - PECO Power Co. -Bradford 220 KV Line (7003)		1,008,467	1,008,467
10	Minor Items	1,286,654	31,709	1,318,363
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44	Minor Item Previously Devoted to Public Service			
45	Minor Items-Other Nonutility Property			
46	TOTAL	$30,018,694	$608,016	$30,626,710

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [x] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, Investments in Subsidiary Companies.

2. Provide a subheading for each company and list thereunder the information called for below. Sub_total by company and give a total in columns (e),(f),(g) and (h).

(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate .

(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.

3. Report separately the equity in undistributed subsidiary earnings since acquisition. The total in column(e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	STOCKS OF SUBSIDIARY COMPANIES			
2	PECO Energy Power Co.:			
3	Common Capital Stock Par $25	10/31/29		50,000
4	Common Capital Stock Par $25	08/19/46		3,000,000
5	Common Capital Stock Par $25	08/19/46		6,050,000
6	Common Capital Stock Par $25	01/10/63		3,000,000
7	Common Capital Stock Par $25	03/16/70		7,500,000
8	Common Capital Stock Par $25	12/10/74		5,000,000
9	SUBTOTAL			24,600,000
10				
11	Next Wave, Series B	06/27/96		0
12				
13	SECO, Capital Stock	10/31/29		10,000
14	EPDC, Capital Stock	03/14/69		1,000
15	EPEC, Capital Stock	05/26/77		1,000
16				
17	Exelon Capital Stock	11/08/96		0
18	PECO Wireless Capital Stock	02/22/96		0
19	Horizon Energy Company, Capital Stock	02/06/95		100,000
20	Energy Trading Company, Capital Stock	12/03/96		0
21	PECO Hyperion Telecommunications	10/09/95		0
22				
23	EQUITY IN UNDISTRIBUTED			
24	SUBSIDIARY COMPANY EARNINGS			
25	Horizon Energy Company			0
26	PECO Energy Power Company			7,375,556
27	Susquehanna Electric Company			(42,085)
28	Eastern PA Development Company			(22,001,114)
29	Eastern PA Exploration Company			(16,426,197)
30	PECO Energy Capital Corp.			(1,187,500)
31	PECO Wireless			0
32	Hyperion Telecommunications			0
33	Exelon Company			
34				
35	PAID IN CAPITAL			
36	Horizon Energy Company			0
37	PECO Energy Power Company			48,740,078
38	Eastern PA Development Company			62,778,895
39	PAID IN CAPITAL (CON'T)			
40	Eastern PA Exploration Company			16,544,000
41	Susquehanna Electric Company			1,050,000
42	TOTAL Cost of Account 123.1 $		TOTAL	

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)(Continued)

4. For any securities, notes, or accounts that were pledged, designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.

5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.

6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.

7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).

8. Report on Line 42, column (a) the total cost of Account 123.1.

Equity in Subsidiary Earnings for Year (e)	Revenues For Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
		50,000		3
		3,000,000		4
		6,050,000		5
		3,000,000		6
		7,500,000		7
		5,000,000		8
0	0	24,600,000	0	9
				10
	20,045,000	20,045,000		11
				12
		10,000		13
		1,000		14
		1,000		15
				16
		0		17
	50,884,644	50,884,644		18
		100,000		19
		0		20
	9,950,000	9,950,000		21
				22
				23
				24
(247,432)		(247,432)		25
6,364,366	(6,346,800)	7,393,122		26
47,963		5,878		27
(1,206,626)		(23,207,740)		28
(7,000)		(16,433,197)		29
3,994,367		2,806,867		20
78,000		78,000		31
(1,165,500)		(1,165,500)		32
(1,404,770)		(1,404,770)		33
				34
				35
	2,400,000	2,400,000		36
	20,000,000	68,740,078		37
	(1,031,771)	61,747,124		38
				39
		16,544,000		40
		1,050,000		41
				42

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, Investments in Subsidiary Companies.

2. Provide a subheading for each company and list thereunder the information called for below. Sub_total by company and give a total in columns (e),(f),(g) and (h).

(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate .

(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.

3. Report separately the equity in undistributed subsidiary earnings since acquisition. The total in column(e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Energy Trading Company			0
2	Exelon Company			0
3	PECO Energy Capital Corp.	07/24/94		48,282,143
4	PECO Energy Cap. Limited Prtshp	07/24/94		100
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	TOTAL Cost of Account 123.1 $		TOTAL	$169,825,876

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)(Continued)

4. For any securities, notes, or accounts that were pledged, designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.

5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.

6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.

7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).

8. Report on Line 42, column (a) the total cost of Account 123.1.

Equity in Subsidiary Earnings for Year (e)	Revenues For Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
	$700,000	$700,000		1
	2,161,968	2,161,968		2
	(2,334,298)	45,947,845		3
		100		4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				20
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
$6,453,368	$96,428,743	$272,707,987	0	42

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column(a); estimates of amounts by function are acceptable. In column(d), designate the department or departments which use the class of material.

2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected - debited or credited. Show separately debit or credits to stores expense-clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments Which Use Material (d)
1	Fuel Stock (Account 151)	$46,282,517	$34,570,861	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	294,302	384,665	Electric
3	Residuals and Extracted Products (Account 153)	0	0	
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	38,989,514	46,804,521	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	66,001,579	54,957,748	Electric & Gas
8	Transmission Plant (Estimated)			
9	Distribution Plant (Estimated)	14,318,591	10,005,204	Electric & Gas
10	Assigned to - Other	(221,370)	6,635,058	Electric & Gas
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	$119,088,314	$118,402,531	
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)			
15	Stores Expense Undistributed (Account 163)	3,830,002	916,740	
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	$169,495,135	$154,274,797	

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA)

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	1997 No. (d)	1997 Amt. (e)
01	Balance-Beginning of Year	92,888.00	$898,600	34,176.00	
02	Acquired During Year:				
03	Issued (Less Withheld Allow.)				
04					
05	Returned by EPA				
06	Purchases/Transfers:				
07					
08					
09					
10					
11					
12					
13					
14					
15	Total				
16	Relinquished During Year:				
17	Charges to Account 509	1,473.00	32,085		
18					
19	Other:				
20					
21	Cost of Sales/Transfers:				
22		33,861.00	206,908		
23					
24					
25					
26					
27					
28	Total	33,861.00	$206,908		
29	Balance-End of Year	57,554.00	$659,607	34,176.00	
30	Sales:				
31	Net Sales Proceeds (Assoc. Co.)				
32					
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Account 158.2)				
36	Balance-Beginning of Year	688.32		688.32	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	688.32			
40	Balance-End of Year	0	0	688.32	
41	Sales:				
42	Net Sales Proceeds (Assoc. Co.)				
43					
44	Net Sales Proceeds (Other)	688.32	46,904		
45	Gains	688.32	46,904		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

issued allowances. Report withheld portions lines 36-40

6. Report on lines 5 allowances returned by the EPA. Report on line 39 the EPA's sales of the withheld allowances. Report on lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.

7. Report on lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).

8. Report on lines 22 - 27 the name of purchasers/transferees of allowances disposed of and identify associated companies.

9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers

10. Report on lines 32-35 & 43-46 the net sales proceeds and gains or losses from allowance sales.

1998		1999		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
34,136.00		34,154.00		1,048,081.00		1,243,435.00	$898,600	01
								02
								03
								04
								05
								06
								07
								08
								09
								10
								11
								12
								13
								14
								15
								16
								17
						1,473.00	32,085	18
								19
						0	0	20
								21
						33,861.00	206,908	22
								23
								24
								25
								26
								27
						33,861.00	$206,908	28
34,136.00	0	34,154.00		1,048,081.00		1,208,101.00	$659,607	29
								30
								31
								32
								33
								34
								35
688.32		688.32		28,890.40		31,643.68	0	36
				1,110.14		1,110.14		37
								38
				556.41		1,244.73	0	39
688.32	0	688.32		29,444.13	0	31,509.09	0	40
								41
								42
								43
				556.41	35,856	1,244.73	82,760	44
				556.41	35,856	1,244.73	82,760	45
								46

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission authorization to use Account 182.1 and period of amortization(mo,yr,to mo,yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	NONE					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecoverd Plant and Regulatory Study Costs[Include in the description of costs, the date of Commission authorization to use Account 182.2, and period of amortization (mo, yr, to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Nuc. Des. Bas. Doc. (Appr. 11/92)					
22	P.B. #2 & #3 (12/1992 - 12/2014)	6,293,761	(183)	407	306,898	5,085,567
23	Limerick #1 (12/1992 - 12/2024)	7,116,755	366	407	265,100	6,170,391
24	Limerick #2 (12/1992 - 12/2029)	7,116,755	366	407	220,112	6,309,404
25	Salem #1 (12/1992 - 12/2016)	9,402,731	188,845	407	408,480	7,581,824
26	Salem #2 (12/1992 - 12/2020)	8,139,023	(249,009)	407	316,575	6,739,087
27						
28	Hydro. Water Chem. Sys:Appr.12/92					
29	P.Bottom #2 (12/1992 - 12/2014)	4,308,099	0	407	210,125	3,483,148
30	P.Bottom #3 (12/1992 - 12/2014)	2,597,191	0	407	126,683	2,098,902
31	Limerick #1 (12/1992 - 12/2024)	1,256,384	0	407	46,538	1,088,178
32	Limerick #2 (12/1992 - 12/2029)	938,240	0	407	29,144	830,866
33	Limerick Com. (12/1992 - 12/2029)	21,360	0	407	662	18,919
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	$47,190,299	($59,615)		$1,930,317	$39,406,286

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [x] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other accounts).

2. For regulatory assets being amortized, show period of amortization in column (a).

3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Debits (b)	CREDITS Account Charged (c)	CREDITS Amount (d)	Balance at End of Year (e)
1	SFAS No. 109 Regulatory Liability	$511,159,259	282	$254,854,670	$2,333,214,418
2					
3	SFAS No. 106 Non-Pension Postretirement Benefits	0	228	14,593,255	232,900,578
4					
5	Decontamination and Decommissioning Funds	1,883,024	228	6,145,470	60,391,737
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44	TOTAL	$513,042,283		$275,593,395	$2,626,506,733

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

MISCELLANEOUS DEFERRED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.

2. For any deferred debit being amortized, show period of amortization in column (a).

3. Minor items (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDIT Account Charged (d)	CREDIT Amount (e)	Balance at End of Year (f)
1	Billilngs in Progress	$25,645,458	$33,146,665	various	$54,563,214	$4,228,909
2						0
3	Delinquent Accounts	1,227,874	7,251,094	142	501,194	7,977,774
4						0
5	Salem Wetlands Acq. Project	285,723	7,728,304	232	7,728,304	285,723
6						0
7	Siting Fees	8,540,851	0			8,540,851
8						0
9	Advance Payments - Salem	9,612,554	35,804,159	various	43,142,371	2,274,342
10						0
11	Limerick #1 & #2 Deferred Exp.	160,547,350	5,874,289	405	24,524,338	141,897,301
12						0
13	Deferred Depr. - 50% Common Plt	45,541,172	0	405	2,356,176	43,184,996
14						0
15	Def. Carry Chrg- 50% Common Plt	194,797,090	0	405	10,078,263	184,718,827
16						0
17	SFAS 112 Postemploy Benefits	13,591,480	900,000	253	4,093,173	10,398,307
18						0
19	Resource Recovery Obsolete Inv.	8,332,988	8,469	various	8,332,987	8,470
20						0
21	O'Brien Contract Buyouts	4,970,700	91,504	912	1,276,804	3,785,400
22						0
23	Minor Items	8,839,257	149,835,754	various	153,099,668	5,575,343
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	DEFERRED REGULATORY COMM. EXPENSES (See pages 350-351)					
49	TOTAL	$481,932,497				$412,876,243

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.

2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	* (A) See Below	$260,683,764	$250,067,163
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	$260,683,764	$250,067,163
9	Gas		
10	* (B) See Below	18,653,558	16,339,331
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	$18,653,558	$16,339,331
17	Other	102,514,772	3,387,978
18	TOTAL (Acct 190)(Total of lines 8,16 and 17)	$381,852,094	$269,794,472

NOTES

< Page 234 Line 2 Column a >

(A) Electric	Beg of Year	End of Year
Decommissioning Expense	14,495,256	15,657,980
Obsolete Inventory	6,520,354	691,419
Environmental Cleanup	3,762,541	3,171,094
Deferred Compensation	121,616	529,156
FAS 109	8,846,258	6,591,846
CIAC	3,084,488	1,908,878
Gain on Reacquired Bonds	529,689	387,724
Lim. #1-Val. of fuel savings	33,250,009	29,955,001
Deferred Fuel	(25,000,400)	(38,402,505)
Value of Generation -Lim #2	11,475,283	11,132,731
Dividend Equivalents	(401,873)	806,941
Pension Expense	91,031,852	73,311,607
Gross Receipts Tax -Lim #2	(37,391)	0
Nuc Design Basis Doc.	(749,556)	(145,336)
Incremental Nuc Fuel Outage	14,329,477	11,889,588
Uncollectible Accounts	49,878,617	53,933,154
Avoided Interest	16,974,493	51,048,082
Merrill Creek	14,848,746	14,455,566
FAS 106	27,376,761	14,829,698
PA Sales & Use Tax	619,475	1,110,518
Hydrogen Water Chemistry Sys	171,358	342,433
Power Rerate	(10,443,289)	(9,259,797)
Interest Income - O'Brien	0	642,727
Contingent Liabilities	0	761,059
NQ Decomm Earnings	0	3,305,326
Investment Reserve	0	1,412,273
TOTAL	260,683,764	250,067,163

< Page 234 Line 10 Column a >

(B) GAS

	Beg of Year	End of Year
Avoided Interest	447,622	1,130,279
Gain on Reacq. Bonds	7,234	(1,790)
Capitalized Inv. Costs	542,289	286,813
CIAC	1,514,289	1,252,153
Dividend Equivalents	36,347	36,347
Pension Expense	12,927,094	11,045,236
Obsolete Inventory	196,027	196,027
Environmental Cleanup	231,687	1,537,295
Deferred Compensation	3,607	3,607
FAS109	895,918	922,483
FAS106	(110,168)	(1,033,126)
Uncollectible Accounts	722,663	(527,112)
Contingent Liabilities	1,238,949	1,491,119
TOTAL	18,653,558	16,339,331

(C) OTHER

Accretion Income	3	0
AMT Deferred	101,736,770	1,348,973
Lim #2-Disallow. costs	8,662	0

Lim #1 - Damaged Nuc Fuel	(1,000)	0
Avoided Interest	770,337	2,039,005
TOTAL	102,514,772	3,387,978

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

CAPITAL STOCK (Accounts 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form(i.e. year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.

2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Exchange (a)	Number of Shares Authorized By Charter (b)	Par or Stated Value Per Share (c)	Call Price at End of Year (d)
1	Common Stock (Account 201)	500,000,000		
2	TOTAL_COM	500,000,000		
3				
4	PREFERRED STOCK (Account 204)	15,000,000		
5	3.80% Series Cumulative			$106.00
6	4.30% Series Cumulative			$102.00
7	4.40% Series Cumulative			$112.00
8	4.68% Series Cumulative			$104.00
9	* 7.96% Series Cumulative (a)			
10	7.48% Series Cumulative (b)			
11	6.12% Series Cumulative (c)			
12	TOTAL_PRE	15,000,000		
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

CAPITAL STOCK (Account 201 and 204)(Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.

4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.

5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.

Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent.)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
222,542,087	$3,517,613,980	0	0			1
222,542,087	3,517,613,980	0	0	0	0	2
						3
						4
300,000	30,000,000		219			5
150,000	15,000,000					6
274,720	27,472,000					7
150,000	15,000,000					8
618,954	61,895,425					9
500,000	50,000,000					10
927,000	92,700,000					11
2,920,674	292,067,425	0	219	0	0	12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

CAPITAL STOCK SUBSCRIBED, CAPITAL STOCK LIABILITY FOR CONVERSION, PREMIUM ON CAPITAL STOCK, AND INSTALLMENTS RECEIVED ON CAPITAL STOCK (Accounts 202 and 205, 203 and 206, 207, 212)

1. Show for each of the above accounts the amounts applying to each class and series of capital stock.
2. For Account 202, Common Stock Subscribed, and Account 205, Preferred Stock Subscribed, show the subscription price and the balance due on each class at the end of year.
3. Describe in a footnote the agreement and transactions under which a conversion liability existed under Account 203, Common Stock Liability for Conversion, or Account 206, Preferred Stock Liability for Conversion, at the end of the year.
4. For Premium on Account 207, Capital Stock, designate with a double asterisk any amounts representing the excess of consideration received over stated values of stocks without par value.

Line No.	Name of Account and Description of Item (a)	Number of Shares (b)	Amount (c)
1	Premium on Capital Stock (Account 207)		
2	Preferred Stock $100 Par Cumulative		
3	4.68% Series	150,000	45,000
4	4.40% Series	274,720	482,210
5	3.80% Series	300,000	686,700
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			
45			
46	TOTAL	724,720	$1,213,910

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)—State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated Value of Capital Stock (Account 209)—State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210)—Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debt identified by the class and series of stock to which related.

(d) Miscellaneous Paid-In Capital (Account 211)—Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	ACCOUNT 210	
2	7.00% Series - Gain on Resale	18,940
3		
4		
5	ACCOUNT 211	
6	Paid in Capital from Treasury	38,728
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	$57,668

Name of Respondent PECO Energy Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

LONG-TERM DEBT (Accounts 221, 222,223, and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221,Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.

2. In column (a), for new issues, give Commission authorization numbers and dates.

3. For bonds assumed by the respondent, include in column(a) the name of the issuing company as well as a description of the bonds.

4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column(a) names of associated companies from which advances were received.

5. For receivers' certificates,show in column(a) the name of the court and date of court order under which such certificates were issued.

6. In column(b) show the principal amount of bonds or other long-term debt originally issued.

7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.

8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.

9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give Commission Authorization numbers and dates) (a)	Principal Amount of Debt issued (b)	Total expense, Premium or Discount (c)
1	Bonds (Account 221)		
2	First and Refunding Mortgage Bonds		
3	6-1/8% Series Due 1997	75,000,000	114,944
4			270,000 D
5			
6	7-3/8% Series Due 2001	80,000,000	132,039
7			(48,800) P
8			
9			
10	9-1/4% Series Due 1999	75,000,000	112,903
11			435,750 D
12			
13			
14	7-1/2% Series Due 1999	250,000,000	2,950,000
15			2,102,500 D
16	8% Series Due 2002	200,000,000	2,331,500
17			998,000 D
18	8-3/4% Series Due 2022	150,000,000	1,758,850
19			1,738,000 D
20	8-5/8% Series Due 2022	125,000,000	275,000
21			1,898,750 D
22	7-1/2% Series Due 2002	100,000,000	230,000
23			515,000 D
24	8-1/4% Series Due 2022	250,000,000	236,111
25			4,222,500 D
26	7-1/8% Series Due 2002	200,000,000	188,899
27			2,522,000 D
28	6-5/8% Series Due 2003	250,000,000	357,475
29			3,722,500 D
30	7-3/4% Series Due 2023	100,000,000	145,338
31			1,420,000 D
32			
33	TOTAL		

LONG-TERM DEBT (Accounts 221, 222,223, and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.

11. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt - Credit.

12. In a footnote, give explanatory particulars (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.

13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.

14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.

15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.

16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
10/01/67	10/01/97	10/01/67	10/01/97	75,000,000	4,593,750	3
						4
						5
12/15/71	12/15/01	12/15/71	12/15/01	80,000,000	5,900,003	6
						7
						8
						9
10/01/89	10/01/99	10/01/89	10/01/99	75,000,000	6,937,500	10
						11
						12
						13
01/15/92	01/15/99	01/15/92	01/15/99	250,000,000	18,750,000	14
						15
04/01/92	04/01/02	04/01/92	04/01/02	200,000,000	16,000,000	16
						17
04/01/92	04/01/02	04/01/92	04/01/22	150,000,000	13,125,000	18
						19
06/01/92	06/01/22	06/01/92	06/01/22	125,000,000	10,781,250	20
						21
07/15/92	07/15/02	07/15/92	07/15/02	100,000,000	7,500,000	22
						23
09/01/92	09/01/22	09/01/92	09/01/02	250,000,000	20,625,000	24
						25
09/01/92	09/01/02	09/01/92	09/01/02	200,000,000	14,250,000	26
						27
03/01/93	03/01/03	03/01/93	03/01/03	250,000,000	16,562,500	28
						29
03/01/93	03/01/23	03/01/93	03/01/23	100,000,000	7,750,000	30
						31
						32
						33

LONG-TERM DEBT (Accounts 221, 222,223, and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.

11. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt - Credit.

12. In a footnote, give explanatory particulars (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.

13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.

14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.

15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.

16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
05/01/93	05/01/23	05/01/93	05/01/23	250,000,000	19,375,000	3
						4
05/01/93	05/01/03	05/01/93	05/01/03	200,000,000	13,000,000	5
						6
08/15/93	08/15/98	08/15/93	08/15/98	225,000,000	12,093,750	7
						8
08/15/93	08/15/05	08/15/93	08/15/05	75,000,000	4,781,250	9
						10
08/15/93	08/15/23	08/15/93	08/15/23	200,000,000	14,250,000	11
						12
11/01/93	11/01/01	11/01/93	11/01/01	250,000,000	14,062,500	13
						14
11/01/93	11/01/24	11/01/93	11/01/24	225,000,000	16,312,500	15
						16
						17
08/01/87	08/01/07	08/01/87	08/01/07	44,687,500	4,823,372	18
						19
						20
						21
						22
06/01/86	06/01/16	06/01/86	06/01/16	0	1,008,074	23
						24
04/01/91	04/01/21	04/01/91	04/01/21	90,000,000	6,637,500	25
						26
04/01/91	04/01/21	04/01/91	04/01/21	27,030,000	2,054,280	27
						28
12/01/91	12/01/22	12/01/91	12/01/21	160,560,000	10,757,520	29
						30
06/01/92	06/01/22	06/01/92	06/01/22	29,540,000	1,957,025	31
						32
[illegible]						33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

LONG-TERM DEBT (Accounts 221, 222,223, and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221,Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.

2. In column (a), for new issues, give Commission authorization numbers and dates.

3. For bonds assumed by the respondent, include in column(a) the name of the issuing company as well as a description of the bonds.

4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column(a) names of associated companies from which advances were received.

5. For receivers' certificates,show in column(a) the name of the court and date of court order under which such certificates were issued.

6. In column(b) show the principal amount of bonds or other long-term debt originally issued.

7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.

8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.

9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give Commission Authorization numbers and dates) (a)	Principal Amount of Debt issued (b)	Total expense, Premium or Discount (c)
1	Floating Rate Salem County Series A	$4,200,000	$106,400
2	Floating Rate Delaware County Series A	50,000,000	1,231,200
3	Floating Rate Delaware County Series B	50,000,000	1,231,200
4	Floating Rate Delaware County Series C	50,000,000	1,231,200
5			
6	DEBENTURES		
7	9% Series Due 2043	228,092,784	0
8	8.72% Series Due 2025	80,520,180	0
9			
10	Other Long - Term Debt (Account 223)		
11	DEMAND PROMISSORY NOTE		
12	Floating Rate Intercompany Demand Note Due 2043	22,809,278	0
13	Floating Rate Intercompany Demand Note Due 2025	8,052,018	0
14			
15			
16	Other Long-Term Debt (Account 224)		
17	POLLUTION CONTROL NOTES		
18	Floating Rate Delaware County Series A Due 2016	24,125,000	688,905
19	Floating Rate York County Series A Due 2016	18,440,000	526,095
20	Floating Rate Salem County Series A Due 2025	23,000,000	750,000
21	Montgomery Cty. PC Rev Ref. Bonds Series A due 2029	82,560,000	5,329,531
22	Montgomery Ct. PC Rev Ref. Bonds Series B due 2029	13,340,000	860,401
23	Montgovery Cty PC Rev Ref. Bonds due 2034	34,000,000	216,610
24			
25	LONG-TERM BANK LOANS		
26	Chemical Bank of New York	117,000,000	258,057
27	First National Bank of Chicago	50,000,000	260,280
28	First Nat'l Bank of Chicago Revolving Credit Agmt	525,000,000	906,250
29	First Nat'l Bank of Chicago Tax Exempt Bank Loan	17,240,000	59,604
30	Fuji Bank	175,000,000	
31			
32			
33	TOTAL		

LONG-TERM DEBT (Accounts 221, 222,223, and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.

11. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt - Credit.

12. In a footnote, give explanatory particulars (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.

13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.

14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.

15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.

16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
09/26/84	12/01/12	09/26/84	12/01/12	4,200,000	143,810	1
07/21/88	12/01/12	07/21/88	12/01/12	50,000,000	1,758,947	2
07/21/88	12/01/12	07/21/88	12/01/12	50,000,000	1,711,496	3
07/21/88	12/01/12	07/21/88	12/01/12	50,000,000	1,731,619	4
						5
						6
07/27/94	07/27/43	07/27/94	07/27/43	228,092,784	* 0	7
12/19/95	12/19/25	12/19/95	12/19/25	80,520,180	0	8
						9
						10
						11
07/27/94	07/27/43	07/27/94	07/27/43	22,809,278	0	12
12/19/95	12/19/25	12/19/95	12/19/25	8,052,018	0	13
						14
						15
						16
						17
09/01/93	08/01/16	09/01/93	08/01/16	24,125,000	815,900	18
09/01/93	08/01/16	09/01/93	08/01/16	18,440,000	623,635	19
09/01/93	03/01/25	09/01/93	03/01/25	23,000,000	791,270	20
06/23/94	06/01/29	06/23/94	06/01/29	82,560,000	2,821,082	21
06/23/94	06/01/29	06/23/94	06/01/29	13,340,000	469,651	22
03/27/96	03/01/34	03/27/96	03/01/34	34,000,000	923,625	23
						24
						25
03/15/89	03/15/96	03/15/89	03/15/96	0	3,186,434	26
03/15/89	03/15/96	03/15/89	03/15/96	0	1,490,250	27
10/04/90	10/03/96	10/04/90	10/03/96	0	3,172,483	28
12/18/95	06/10/97	12/18/95	06/10/97	17,240,000	434,433	29
11/06/95	11/06/97	11/06/95	11/06/97	175,000,000	10,357,103	30
						31
						32
[illegible]						33

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo., Da., Yr) 12/31/96	Year of Report Dec. 31, 1996

LONG-TERM DEBT (Accounts 221, 222,223, and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221,Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.

2. In column (a), for new issues, give Commission authorization numbers and dates.

3. For bonds assumed by the respondent, include in column(a) the name of the issuing company as well as a description of the bonds.

4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column(a) names of associated companies from which advances were received.

5. For receivers' certificates,show in column(a) the name of the court and date of court order under which such certificates were issued.

6. In column(b) show the principal amount of bonds or other long-term debt originally issued.

7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.

8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.

9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give Commission Authorization numbers and dates) (a)	Principal Amount of Debt issued (b)	Total expense, Premium or Discount (c)
1	Other Long-Term Debt (Account 224)		
2	MEDIUM TERM NOTES		
3	9.08% Series Due 1999	30,000,000	69,750
4			187,500 D
5	9.02% Series Due 1996	10,000,000	23,250
6			60,000 D
7	9.00% Series due 1996	20,000,000	46,500
8			120,000 D
9	9.10% Series due 2005	5,000,000	11,625
10			33,750 D
11	9.10% Series due 2005	5,000,000	11,625
12			30,000 D
13	9.90% Series due 2005	10,000,000	23,250
14			67,500 D
15	9.00% Series due 1996	5,000,000	11,625
16			27,500 D
17			
18	Other Long-Term Debt (Account 224 Con't)		
19	MEDIUM TERM NOTES (Con't)		
20	6.42% Series due 1996	12,400,000	28,830
21			24,800 D
22	6.05% Series due 1995	12,400,000	28,830
23			18,600 D
24	6.96% Series due 1997	10,000,000	23,250
25			25,000 D
26	7.41% Series due 1998	12,400,000	28,830
27			55,800 D
28	7.00% Series due 1997	2,000,000	4,650
29			7,000 D
30			
31			
32			
33	TOTAL	$5,393,709,260	$77,489,380

LONG-TERM DEBT (Accounts 221, 222,223, and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.

11. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt - Credit.

12. In a footnote, give explanatory particulars (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.

13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.

14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.

15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.

16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
12/12/89	12/20/99	12/12/89	12/20/99	30,000,000	2,724,000	3
						4
12/13/89	12/20/96	12/13/89	12/20/96	0	871,934	5
						6
12/14/89	12/30/96	12/14/89	12/30/96	0	1,938,750	7
						8
12/20/89	01/14/05	12/20/89	01/14/05	5,000,000	455,000	9
						10
12/20/89	01/14/05	12/20/89	01/14/05	5,000,000	455,000	11
						12
12/20/89	01/14/05	12/20/89	01/14/05	10,000,000	909,000	13
						14
01/11/90	01/30/96	01/11/90	01/30/96	0	35,000	15
						16
						17
						18
						19
07/05/94	03/29/96	07/05/94	03/29/96	0	194,597	20
						21
07/05/94	10/02/95	07/05/94	10/02/95	0	0	22
						23
07/07/94	04/15/97	07/07/94	04/15/97	10,000,000	696,000	24
						25
07/11/94	07/08/98	07/11/94	07/08/98	12,400,000	918,840	26
						27
07/11/94	07/11/97	07/11/94	07/11/97	2,000,000	140,000	28
						29
						30
						31
						32
[redacted]				$4,587,596,760	$303,657,633	33

< Page 257.2 Line 19 Column I >

Interest in accounts 04300-3003 $1,074,894 & 04310-3003 $19,912,500 in Other Interest totals $20,987,394.

Interest in account 04300-3002 totals $2,466,253.

Interest in accounts 04300-3009 $33,243 & 04310-3004 $1,074,894 in Other Interest totals $1,108,137.

Interest in account 04300-3008 totals $30,829.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [x] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.

2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.

3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete line 27 and provide the substitute page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	$517,204,341
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	See Attached Supplement (a)	9,712,627
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See Attached Supplement (b)	409,776,185
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See Attached Supplement (c)	103,572,923
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Attached Supplement (d)	210,405,130
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	622,715,100
28	Show Computation of Tax:	
29	Federal Income Tax at 35%	217,950,286
30	Less: AMT Credits	(70,914,799)
31		
32		
33	Net Federal Income Tax Accrued on a Separate Basis	147,035,487
34		
35		
36	*	
37	*	
38	*	
39		
40		
41		
42		
43		
44		

< Page 261 Line 36 Column a >

RECONCILIATION OF REPORTED NET INCOME WITH
TAXABLE INCOME FOR FEDERAL INCOME TAXES

(a) DETAIL OF TAXABLE INCOME NOT REPORTED ON BOOKS

Leasing Interest Income	$1,553,304
Escrow Acct. Int. & Div. Net of Taxes	6,131,867
CIAC	151,756
Audit Adjustments	320,700
Interest Income - NRG/O'Brien	1,555,000
TOTAL	9,712,627

(b) DEDUCTIONS RECORDED ON BOOKS NOT DEDUCTED FOR RETURN

Federal Income Tax		
Charged to Operations	$149,006,095	
Charged to Non-Operations	(1,970,608)	
Prior Period	(26,850,097)	120,185,390
State Income Tax Adjustments		(435,781)
Investment Tax Credit Adj.		(15,962,659)
PA Sales & Use Tax		1,200,000
Lim #1 & #2 Common Declar. Order Writeoff		29,944,500
Deferred Income Taxes		165,494,055
Unbilled Revenue - Book		30,200,000
MGO writedown		2,622,170
PURTA Additional Assessment		722,598
Environmental Cleanup Costs		1,807,795
Hydro Gen Water Chem. Systems		413,153
Amortization of Premium on Reacq. Bonds		27,021,794
Investment Reserve		3,414,431
Nondeduct. Business Meals		808,685
Avoided Interest		17,276,428
Decommissioning Expense		3,630,720
Clearing Accounts		5,810,978
Section 280F Leased Vehicles adjustment		324
Lobbying Expenses		1,400,000
Contingent Liabilities		2,446,771
Dividend from PECO Energy Capital Corp		1,489,888
Power Rerate		2,197,633
Design Basis Documentation Costs		1,517,165
Uncollectible Accounts		6,570,147
TOTAL		409,776,185

< Page 261 Line 37 Column a >

(c) INCOME RECORDED ON BOOKS NOT INCLUDED IN RETURN

AFUDC	$19,583,209

Deferred Fuel	66,151,011
Incremental Nuc Outage Costs	5,891,314
Amort on Reacquired Bonds	875,951
Insurance reserve premiums refunded	792,903
STAC Give Back	2,579,698
Prepaid Rental Income	69,972
Equity in Earnings of Subsidiaries	7,618,865
Investment adjustment	10,000
TOTAL	$103,572,923

(d) DEDUCTIONS ON RETURN NOT CHARGED AGAINST BOOK INCOME

Nuc Fuel Excess of Tax Depr over Book Burn	$16,077,214
Excess of Lib. Depr over Book Depr	12,572,876
Premium on Early Bond Retirements	1,171,861
Loss on ACRS Retirements	11,452,924
Preferred Dividend Credit	483,504
Easements and Clearing Rights of Way	719,568
Salem Estuary	2,856,877
FAS 106 - Post Retire. Benefits	27,676,009
Cost of Removal	2,478,296
Software	3,102,019
Leasing Rental Expense	15,063,288
Pensions	35,811,939
Merrill Creek Amortization	643,368
Unbilled Revenue - Tax	36,750,000
Loss on Sale of Property	6,853,369
Obsolete Inventory	9,156,523
Compensation from LIPA	10,000
Long Term Incentive Plan	2,027,737
Charitable Contributions	3,232,940
Repair Allowance	22,264,818
TOTAL	210,405,130

< Page 261 Line 38 Column a >

PECO Energy Company is a member of a group including both utility and non-utility companies which files a consolidated Federal Income Tax return. Taxable income for accrual purposes reported on Page 261 is computed on a separate return basis. The following information concerning the consolidation is furnished in accordance with the instructions on Page 261.

NAME		Consolidated Tax Allocated
Utility Group		
PECO Energy Co.	$147,035,487	
PECO Energy Power Co.	216,387	
Susquehanna Electric Co.	(95,055)	
Susquehanna Power Co.	3,487,817	
PECO Energy Capital Corp.	1,345,485	
TOTAL Consolidated - Utility Group		$151,990,121

Nonutility Group		
Energy Performance Serv. Inc.	(330,000)	
Eastern Penn. Expl. Co.	(3,500)	
Eastern Penn. Dev. Co.	(500)	
Adwin Realty Co.	(436,941)	
Adwin Equip. Co.	94,000	
Buttonwoods Assoc. Inc	(3,255)	
Adwin Invest. Co.	(169,540)	
Adwin Schuylkill Cogen Co.	112,900	
Horizon Energy Co.	(270,018)	
PECO Wireless	(493,110)	
Energy Trading Co.	0	
Exelon Corp.	0	
TOTAL Consolidated - Nonutility Group		(1,499,964)
TOTAL CONSOLIDATED		$150,490,157

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.

2. Include on this page, taxes paid during the year and charged direct to final accounts,(not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.

3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued,(b)amounts credited to proportions of prepaid taxes chargeable to current year, and(c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.

4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See Instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal Income	$7,813,958		$122,426,475	$133,000,000	
2	Federal Unemployment Comp.	3,743		420,946	422,689	
3	Federal Old Age Benefits	118,364		30,639,428	30,680,702	
4	Federal Excise	0		99,600	0	1
5	Federal Telephone & Telegraph	126,000		99,600		
6	SUBTOTAL	8,062,065	0	153,686,049	164,103,391	1
7						
8	Federal Superfund - 1996			938,400		
9	Federal Superfund - 1995	941,899		(941,907)		
10						
11	SUBTOTAL - FEDERAL SUPERFUND	941,899	0	(3,507)	0	0
12						
13	Pennsylvania (PA) Income Tax	41,410,171		60,451,720	77,457,289	
14	SUBTOTAL	41,410,171	0	60,451,720	77,457,289	0
15						
16	PA Capital Stock - 1993	1,605,912		(960,888)	(481,573)	
17	PA Capital Stock - 1994	3,397,516		0	(27,479)	
18	PA Capital Stock - 1995	5,099,250		(144,333)	3,335,587	
19	PA Capital Stock - 1996			42,602,142	35,127,784	
20	SUBTOTAL - PA Capital Stock	10,102,678	0	41,496,921	37,954,319	0
21						
22	PA Gross Receipts - 1993	270,490		0	270,490	
23	PA Gross Receipts - 1994	600,000		(49,322)	550,678	
24	PA Gross Receipts - 1995	21,620,236	(6,803)	(9,361)	21,121,430	
25	PA Gross Receipt - 1996			160,335,279	146,262,870	
26	SUBTOTAL - PA Gross Receipts	22,490,726	(6,803)	160,276,596	168,205,468	0
27						
28	PA Real Estate - 1995	6,702,836		(2,979,969)	3,722,867	
29	PA Real Estate - 1996			63,269,291	55,213,513	
30	SUBTOTAL - PA Real Estate	6,702,836	0	60,289,322	58,936,380	0
31						
32	PA Unemployment Compensation	18,880		7,576		
33	PA Gross Premiums	(42,708)		321,020	278,294	
34	PA Corporate Loans	60,000		35,000	53,787	
35	PA Overpayment of PY Tax	0		(239,828)	(115,126)	
36	PA Sales & Use	5,505,346		1,200,000		
37	PA STAC Give Back	2,579,697		(2,579,697)		
38						
39						
40						
41	TOTAL					

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.

2. Include on this page, taxes paid during the year and charged direct to final accounts,(not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.

3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued,(b)amounts credited to proportions of prepaid taxes chargeable to current year, and(c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.

4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See Instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	New Jersey (NJ) Income	$536,529		$1,374,304	$3,384,632	
2	NJ Personal Property					
3	NJ Real Estate			1,596,000	1,628,224	
4	NJ Real Estate Local				274,931	
5	NJ Excise	11,604	70,959	(11,604)		
6						
7	Maryland (MD) Income	6,677,290		(13,325)	6,821,542	
8	MD Personal Property	0				
9	MD Gross Receipts	18,639		(18,639)		
10	MD Use Tax					
11						
12	Local Real Estate		645,265	4,627,766	3,612,636	
13	Local Merch/Bus. Privilege	(11,694)		37,337	25,643	
14	Local Realty Occupany			1,156,630	1,135,228	
15	Local Franchise			252,000	1,329	
16	Local General Service Fee					
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	$105,063,958	$709,421	$483,941,641	$523,757,967	$1

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column(a).

6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. Designate debit adjustments by parentheses.

7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.

8. Report in columns (i) through (l) how the taxes were distributed. Report in column (i) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also show in column (l) the taxes charged to utility plant or other balance sheet accounts.

9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				
(Taxes Accrued (Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1 (i)	Extraordinary Items (Account 409.3) (j)	Adjustment to Ret. Earnings (Account 439) (k)	Other (l)	Line No.
($1,473,799)		$1,640,180			($265,876)	1
						2
(32,224)		1,596,000				3
(274,931)						4
	70,959	(11,604)				5
						6
(157,577)		18,164			(31,489)	7
						8
		(18,639)				9
						10
						11
2,691,155	2,321,290	4,054,809			572,957	12
					37,337	13
21,402		1,140,000			16,630	14
250,671		228,000			24,000	15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
					*	37
						38
						39
						40
$66,929,641	$2,391,430	$436,951,355	0	0	$46,990,286	41

< Page 263 Line 38 Column 1 >

Distribution of Taxes Charged shown in Col. L, Other

Kind of Tax	Accts Charged
Fed. Income	143;146;184;232;234;236;409.2;1409.1
Fed. Unemp. Comp.	186;408.2
Fed. Old Age Ben.	186;408.2;1408.1
Fed. Tel. & Telegr.	1408.1
Fed. Superfund	146;236;408.2;1408.1
PA Income Tax	146;236;409.2;1409.1
PA Capital Stock	236;1408.1
PA Gross Receipts	131;1408.1
PA Real Estate	131;236;1408.1
PA Unempl Comp	186;408.2;1408.1
PA Gross Prem.	165
PA Corp. Loans	431
PA Overpmt of PY Tax	186;419
PA Sales & Use	236
PA STAC Give Back	1408.1
NJ Income	409.2;1409.1
NJ Per. Prop.	
NJ Real Estate	
NJ Excise	
MD Income	236;409.2;1409.1
MD Per. Prop.	
MD Gross Receipts	
MD Use Tax	
Local Real Estate	143;165;408.2;1408.1
Local Merch/Bus Priv.	408.2
Local Realty Occupany	236;1408.1
Local Franchise	1408.1
Local General Services	
West Va. Property Tax	131; 1408.1

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column(g). Include in column(i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	11,039,548			411.4	983,947	
4	7%						
5	10%	326,499,720			411.4	14,386,452	* 541,786
6							
7							
8	TOTAL	$337,539,268		0		$15,370,399	$541,786
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Utility						
11	4%	1,068,186			411.4	66,762	
12	10%	10,748,645			411.4	465,642	
13	Subtotal-Gas	11,816,831				532,404	
14							
15	Common Utility						
16	4%	195,281			411.4	13,911	
17	10%	1,067,686			411.4	45,945	
18	Subtotal-Common	1,262,967				59,856	
19							
20							
21	Grand Total	350,619,066				15,962,659	541,786
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

Name of Respondent PECO Energy Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (Continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	Adjustment Explanation	Line No.
			1
			2
10,055,601	34 YEARS		3
0			4
312,655,054	34 YEARS		5
0			6
0			7
$322,710,655			8
			9
0			10
1,001,424	37 YEARS		11
10,283,003	37 YEARS		12
11,284,427			13
0			14
0			15
181,370			16
1,021,741			17
1,203,111			18
			19
			20
335,198,193			21
			22
			23
			24
			25
			26
			27
			28
			29
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

< Page 266 Line 5 Column g >

ADJUSTMENT EXPLANATION

Description	Elec.	Gas	Common	Total
ITC on TBT Assets-131	420,664	0	0	420,664
Lim 1 Dec. Order amort-186	121,122	0	0	121,122
TOTAL	541,786	0	0	541,786

Alloc. of Common to Class of Service	Elec.	Gas	Total
Deferred 4%	0	0	0
Deferred 10%	0	0	0
TOTAL	0	0	0
Amortized 4%	12,293	1,618	13,911
Amortized 10%	40,363	5,582	45,945
TOTAL	52,656	7,200	59,856

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, whichever is greater) may be grouped by classes.

Line No.	Description of Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Limerick Fuel Savings	$21,333,275	405	$4,923,072	0	$16,410,203
2						
3	Sale/Leaseback Merrill Creek	23,669,127	540	643,369	0	23,025,758
4						
5	Lease payments-sale of Merrill Crk	28,615,844	525	14,585,012	15,493,414	29,524,246
6						
7	Normalization of nuclear outage	35,314,252	524,532	45,218,399	39,327,085	29,422,938
8						
9	Gas refunds rec'd from suppliers	5,098,694	various	2,469,783	2,219,211	4,848,122
10						
11	Long Island Nuclear Fuel	10,000	186	10,000	0	0
12						
13	Environmental Liabilities	33,039,107	various	4,522,779	9,886,611	38,402,939
14						
15	SFAS 112 Postemployment Ben. Liab.	13,591,480	186	4,093,173	900,000	10,398,307
16						
17	Peach Bottom #1 Decom. Fund	442,313		0	0	442,313
18						
19	SFAS No. 115 Unrealized Gains	18,563,116		0	7,303,110	25,866,226
20						
21	Liab for LLRW Pmts	1,845,966	various	1,897,140	820,276	769,102
22						
23	Gas HH Contracts - 9/95	2,765,882	various	2,853,349	87,528	61
24						
25	Conemaugh Mine Closing Escrow	1,760,741		0	81,247	1,841,988
26						
27	Minor Items	5,431,546	various	89,511,636	90,966,348	6,886,258
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	$191,481,343	[redacted]	$170,727,712	$167,084,830	$187,838,461

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ACCUMULATED DEFERRED INCOME TAXES — ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.

2. For Other (Specify), include deferrals relating to other

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	199,633		99,816
5	Other			
6				
7				
8	TOTAL Electric(Enter Total of lines 3 thru 7)	$199,633	0	$99,816
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)	0	0	0
16	Other (Specify)			
17	TOTAL (Acct 281) (Total of 8,15,and 16)	$199,633	0	$99,816
18	Classification of TOTAL			
19	Federal Income Tax	187,369		93,684
20	State Income Tax	12,264		6,132
21	Local Income Tax			

NOTES

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ACCUMULATED DEFERRED INCOME TAXES -- ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

income and deductions.

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
						99,817	4
						0	5
						0	6
						0	7
						$99,817	8
							9
						0	10
						0	11
						0	12
						0	13
						0	14
						0	15
						0	16
						$99,817	17
							18
						93,685	19
						6,132	20
							21

NOTES(Continued)

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ACCUMULATED DEFERRED INCOME TAXES -- OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.

2. For Other (Specify), include deferrals relating to other

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	* $3,348,450,205	$21,642,309	($3,067,332)
3	Gas	159,703,883	(11,171,846)	20,466
4	Other (Define)	22,541,880	1,299,468	30,015
5	TOTAL (Enter Total of lines 2 thru 4)	$3,530,695,968	$11,769,931	($3,016,851)
6	Other (Specify)			
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	$3,530,695,968	$11,769,931	($3,016,851)
10	Classification of TOTAL			
11	Federal Income Tax	2,954,243,978	10,014,127	(3,025,995)
12	State Income Tax	576,451,990	1,755,804	9,144
13	Local Income Tax			

NOTES

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ACCUMULATED DEFERRED INCOME TAXES -- OTHER PROPERTY (Account 282) (Continued)

income and deductions.

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
[redacted]							1
($746,916)		various	$947,364,143	282	$1,225,720,133	$3,650,768,920	2
		190	12,076,045	186	11,323,126	147,758,652	3
			3,067,031	186	16,254,344	36,998,646	4
($746,916)	0		$962,507,219		$1,253,297,603	$3,835,526,218	5
						0	6
						0	7
						0	8
($746,916)	0		$962,507,219		$1,253,297,603	$3,835,526,218	9
[redacted]							10
(610,500)			917,435,084		1,198,093,260	3,247,331,776	11
(136,416)			45,072,135		55,204,343	588,194,442	12
						0	13

NOTES(Continued)

< Page 274 Line 2 Column b >

CHANGES DURING THE YEAR

(A) ELECTRIC

	BEG BAL	END BAL
Liberalized Depr. Excl Lim	443,913,772	1,287,387,365
FAS 109	1,995,517,008	2,241,435,155
Lib. Depr. Limerick	841,818,935	10,742,905
AMT - Operating	1,064,711	0
Tax Benefits Transf	18,302,350	22,189,438
South Georgia Adjust	2,829,025	2,829,025
PUC Adjustment	25,021,902	24,274,986
Prelim Eng Basis Design	1,648,802	1,648,802
Amort. of Software	4,578,600	7,735,422
Audit Exp/Dep Settlements	13,755,100	13,294,516
Salem Estuary	0	1,507,178
AFUDC	0	37,724,128
TOTAL ELECTRIC	3,348,450,205	3,650,768,920

(B) GAS

Liberalized Depreciation	76,280,544	83,491,514
FAS 109	67,110,386	63,553,547
AMT - Operating	16,312,953	0
AFUDC	0	713,591
TOTAL GAS	159,703,883	147,758,652

(C) OTHER

FAS 109	9,601,914	20,867,392
Common - Liberalized Depr.	12,939,966	14,716,553
AFUDC	0	1,414,701
TOTAL OTHER	22,541,880	36,998,646

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.

2. For Other (Specify), include deferrals relating to other

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Early Bond Retirements	$123,327,341		$8,970,514
4	Cost of Lost Gen. at Cromby	160,417		5,904
5	Lim Readiness to Serve Costs	27		27
6	Lim #1 O&M	20,634,137		760,980
7	Lim #1 Def Rev	(366,049)		
8	Other	6,276,334	2,522,168	(335,233)
9	TOTAL Electric (Total of lines 3 thru 8)	$150,032,207	$2,522,168	$9,402,192
10	Gas			
11	Early Bond Retirements	6,799,095		607,833
12	Deferred Fuel	(1,598,725)	13,900,864	
13				
14				
15				
16	Other	(4,874,232)	2,392,593	(68,306)
17	TOTAL Gas (Total of lines 11 thru 16)	$326,138	$16,293,457	$539,527
18	Other (Specify)			
19	TOTAL (Acct 283) (Enter Total of lines 9,17 and 18)	$150,358,345	$18,815,625	$9,941,719
20	Classification of TOTAL			
21	Federal Income Tax	114,710,401	14,213,843	8,139,581
22	State Income Tax	35,647,944	4,601,782	1,802,138
23	Local Income Tax			

NOTES

Name of Respondent PECO Energy Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283)(Continued)

income and deductions.

3. Provide in the space below explanations for page 276 and 277. Include amounts relating to insignificant items listed under Other.

4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credits to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
[redacted]							1
[redacted]							2
		190	$141,965			$114,214,862	3
					276	154,789	4
						0	5
					36,972	19,910,129	6
						(366,049)	7
94,824			306,013			8,922,546	8
$94,824			$447,978		$37,248	$142,836,277	9
[redacted]							10
		190	9,024			6,182,238	11
				174	46,011	12,348,150	12
						0	13
						0	14
						0	15
			388,064		2	(2,801,395)	16
			$397,088		$46,013	$15,728,993	17
						0	18
$94,824			$845,066		$83,261	* $158,565,270	19
[redacted]							20
72,469			(1,659,999)		29,301	122,546,432	21
22,355			2,505,065		53,690	36,018,568	22
						0	23

NOTES (Continued)

< Page 277 Line 19 Column K >

CHANGES DURING THE YEAR

(A) OTHER ELECTRIC	Beg Bal	End Bal
Rate Change	(787,209)	0
Unbilled Revenue	3,326,688	5,056,817
Limerick #2 O&M	8,953,706	8,686,430
FAS 109	(6,175,512)	(6,481,519)
Banked Vacation & Absences	958,661	958,661
Deferred Fuel	0	24,587
Donations	0	94,820
Vac/Hol Pay	0	433,265
DOE Decontamination/Decomm.	0	149,485
TOTAL OTHER ELECTRIC	6,276,334	8,922,546
(B) OTHER GAS		
STAC	(191,630)	0
Rate Change	(89,248)	0
Unbilled Revenue	(4,665,603)	(2,485,580)
FAS 109	(170,330)	(558,394)
Banked Vacation & Absences	242,579	242,579
TOTAL OTHER GAS	(4,874,232)	(2,801,395)

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

OTHER REGULATORY LIABILITIES (Account 254)

1. Reporting below the particulars (details) called for concerning other regulatory liabilities which are created through the ratemaking actions of regulatory agencies (and not includable in other amounts).
2. For regulatory liabilities being amortized, show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	DEBITS Account Credited (b)	DEBITS Amount (c)	Credits (d)	Balance at End of Year (e)
1	Sale of Keystone Emission Allowances		$19,290	$11,410	$34,153
2					
3	Sale of Conemaugh Emission Allowances		53,348	57,206	108,019
4					
5	Sale of PECO Emission Allowances		56,665	14,145	42,342
6					
7	SFAS No. 109 Regulatory Liability		20,768,539	21,912,566	21,912,566
8					
9	Minor items		456	0	(21,819)
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41	TOTAL		$20,898,298	$21,995,327	$22,075,261

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.

2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.

3. If increases or decreases from previous year (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	$1,366,398,166	$1,381,593,143
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr.4)	740,651,017	730,236,764
5	Large (or Ind.) (See Instr.4)	1,084,026,855	1,139,503,003
6	(444) Public Street and Highway Lighting	32,814,903	34,256,679
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways	46,978,924	45,233,781
9	(448) Interdepartmental Sales	5,864,682	5,711,472
10	TOTAL Sales to Ultimate Consumers	$3,276,734,547	$3,336,534,842
11	(447) Sales for Resale	$522,951,548	$366,641,756
12	TOTAL Sales of Electricity	$3,799,686,095	$3,703,176,598
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	$3,799,686,095	$3,703,176,598
15	Other Operating Revenues		
16	(450) Forfeited Discounts	$10,535,935	$9,949,079
17	(451) Miscellaneous Service Revenues	2,574,480	2,225,717
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	16,987,772	13,230,550
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	23,531,489	24,882,742
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	$53,629,676	$50,288,088
27	TOTAL Electric Operating Revenues	$3,853,315,771	$3,753,464,686

ELECTRIC OPERATING REVENUES (Account 400)(Continued)

4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

5. See pages 108-109, Important Changes During Year, for important new territory added and important rate increases or decreases.

6. For lines 2,4,5,and 6, see page 304 for amounts relating to unbilled revenue by accounts.

7. Include unmetered sales. Provide details of such sales in a footnote.

MEGAWATT HOURS SOLD		AVG. NO. CUSTOMERS PER MONTH		Line No.
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	
[redacted]				1
10,657,327	10,660,415	1,321,642	1,318,863	2
[redacted]				3
6,409,621	6,222,490	141,690	140,991	4
14,976,015	15,868,993	3,352	3,448	5
192,427	195,054	948	926	6
				7
638,800	594,543	3	3	8
71,259	69,543	1	1	9
32,945,449	33,611,038	1,467,636	1,464,232	10
21,167,916	14,780,675	55	18	11
54,113,365	48,391,713	1,467,691	1,464,250	12
				13
54,113,365	48,391,713	1,467,691	1,464,250	14

Line 12, Column (b) includes $ (25,950,000) of unbilled revenues.

Line 12, Column (d) includes (327,000) MWH relating to unbilled revenues.

Name of Respondent	This Report Is:	Date of Report (Mo., Da., Yr.)	Year of Report
PECO Energy Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customers, average KWh per customer, and average revenue per KWh, excluding data for Sales for Resale which is reported on pages 310-311.

2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," pages 300-301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.

3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.

4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).

5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.

6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales per Customer (e)	Revenue per KWh Sold (f)
1	Residential Service	7,524,899	$1,065,743,336	1,167,557	6,444	14.1628¢
2	Residential Heating Service	2,765,279	277,759,849	154,085	17,946	10.0445¢
3	Off-Peak Water Service	381,149	26,654,981	*		6.9933¢
4	Unbilled	(14,000)	(3,760,000)			26.8571¢
5	TOTAL RESIDENTIAL SALES - 440	10,657,327	1,366,398,166	1,321,642	8,063	12.8212¢
6						
7	General Service	6,481,441	746,698,298	141,690	45,743	11.5205¢
8	Private Outdoor Lighting	9,002	1,854,832			20.6046¢
9	Com. Meas. Therm. Storage	178	7,887	0		4.4308¢
10	Unbilled	(81,000)	(7,910,000)			9.7654¢
11	TOTAL SMALL COM. & IND. -442-1	6,409,621	740,651,017	141,690	45,236	11.5553¢
12						
13	Primary Distribution Power	1,130,531	108,055,933	1,084	1,042,925	9.5579¢
14	High Tension Power	13,424,549	964,082,812	2,268	5,919,113	7.1814¢
15	High Tension Power Supple. Energy	652,935	26,168,110			4.0077¢
16	Unbilled	(232,000)	(14,280,000)			6.1551¢
17	TOTAL LARGE COM. & IND. - 442-2	14,976,015	1,084,026,855	3,352	4,467,784	7.2384¢
18						
19	Street Lighting - City of Phil.	88,803	13,680,929	10	8,880,300	15.4059¢
20	Street Lighting - Energy Only	47,018	9,493,512	344	136,680	20.1912¢
21	Alley Lighting Rider	17	4,088	1	17,000	24.0470¢
22	Street Lighting - Suburbs	16,908	5,116,405	396	42,696	30.2602¢
23	Traffic Lighting	39,681	4,519,969	197	201,426	11.3907¢
24	TOTAL PUBLIC ST & HWY -444	192,427	32,814,903	948	202,982	17.0531¢
25						
26	SEPTA and AmTRAK (EP)	638,800	46,978,924	3	212,933,333	7.3542¢
27	TOTAL SALES TO RR AND RDWAYS -446	638,800	46,978,924	3	212,933,333	7.3542¢
28						
29	Interdepartmental Sales	71,259	5,864,682	1	71,259,000	8.2300¢
30	TOTAL INTERDEPARTMENTAL SALES-448	71,259	5,864,682	1	71,259,000	8.2300¢
31						
32						
33				0		
34						
35						
36			*			
37						
38						
39						
40						
41	Total Billed					
42	Total Unbilled Rev.(See Instr. 6)					
43	TOTAL	32,945,449	$3,276,734,547	1,467,636	22,447	9.9459¢

< Page 304 Line 3 Column d >

Page 304

Number of customers included in other rate classifications.

	Ave. Number of Customers (d)	Kwh of Sales Per Customer (e)	Rev. per Kwh Sold (f)
Line 3 Off-Peak Water	100,169	15,144	6.9933 cents
Line 7 Private Outdoor Lighting	3,226	2,790	20.6047 cents
Line 13 High Tension Power Suppl.	7	93,276,429	4.0078 cents

< Page 304 Line 33 Column C >

Estimated fuel adjustment revenue included in rate schedules.

TOTAL OF RATE SCHEDULE		
Residential Service	R	($13,334,027)
Residential Service	R-M	(142,024)
Residential Service	R-S	(21,318,451)
Electric House Heating	W-H	(12,786,416)
Off-Peak Water Heat. Serv	W-H	(1,737,774)
Unrestr. Water Heat. Serv	W-H	(24,622)
Residential Sales		(49,343,314)
General Service	GS	(29,970,459)
Private Outdoor Lighting	POL	(41,624)
Small Com. & Ind. Sales		(30,012,083)
Primary Distrib. Power	PD	(5,227,480)
High Tension Power	HT	(62,073,985)
Large Com. & Ind. Sales		(67,301,465)
Street Ltng.-City of Phil	SL-P	(410,618)
Street Ltng.-Suburban	SL-S	(78,181)
Alley Lighting Rider	SLP-AL	(79)
Traffic Lighting	TL	(183,477)
Street Lighting	SL-E	(217,403)
Public St & Hwy Lighting		(889,758)
Sales to RR & Rways	EP	(2,953,757)
Border Line Interchange	BLI	(1,087)
Total Fuel Adjustment Revenue		(150,501,464)

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. *Enter the name of the purchaser in column (a). Do note* abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. *In column (b), enter a Statistical Classification Code* based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer *or seller can unilaterally get out of the contract.*

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

IU - for intermediate-term service from a desgnated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

Line No.	Name of Company or Public Authority [Footnote Affiliations] (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	NONASSOCIATED UTILITIES					
2	Alabama Electric Cooperative	OS	FERC 1	N/A	N/A	N/A
3	Allegheny Power Service Corporation	OS	"	N/A	N/A	N/A
4	American Electric Power	OS	"	N/A	N/A	N/A
5	Arizona Public Service Company	OS	"	N/A	N/A	N/A
6	Arkansas Electric Cooperative Corp.	OS	"	N/A	N/A	N/A
7	Atlantic City Electric Company	OS	"	N/A	N/A	N/A
8	Baltimore Gas & Electric Company	OS	"	N/A	N/A	N/A
9	Carolina Power & Light Company	OS	"	N/A	N/A	N/A
10	Central Illinois Public Service Company	OS	"	N/A	N/A	N/A
11	Central Virginia Electric Cooperative	OS	"	N/A	N/A	N/A
12	CINergy Services Inc.	OS	"	N/A	N/A	N/A
13	Cleveland Electric Illuminating Company	OS	"	N/A	N/A	N/A
14	Cleveland Public Power	OS	"	N/A	N/A	N/A

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this listing. Enter "Total" in column (a) as the last line of the schedule. Report subtotals and total for columns (g) through (k).

5. In column (c), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns(e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatthours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled on the last line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on page 401, line 24.

10. Footnote entries as required and provide exptanations following all required data.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
					1
1,845		39,183		39,183	2
404,666	535,286	7,140,265		7,675,551	3
351,057	1,153,604	5,689,859		6,843,463	4
4,921		94,490		94,490	5
615		6,711		6,711	6
853,569	243,811	17,015,461		17,259,272	7
416,352	1,781,852	9,904,353		11,686,205	8
68,310	207,737	1,581,187		1,788,924	9
201,917	1,598,870	3,810,521		5,409,391	10
41,557	37,246	570,379		607,625	11
242,857	968,919	5,250,067		6,218,986	12
10,072	750	229,147		229,897	13
26,195	89,571	513,577		603,148	14

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the *Purchased Power schedule (page 326-327).*

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the *contract defined as the earliest date that either buyer* or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF *service except that "intermediate-term" means longer than* one year but less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

IU - for intermediate-term service from a desgnated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

Line No.	Name of Company or Public Authority [Footnote Affiliations] (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Commonwealth Edison Company	OS	FERC 1	N/A	N/A	N/A
2	Consolidated Edison Company of NY	OS	"	N/A	N/A	N/A
3	Dayton Power & Light Company	OS	"	N/A	N/A	N/A
4	Delmarva Power & Light	OS	"	N/A	N/A	N/A
5	Delmarva Power & Light	OS	"	N/A	N/A	N/A
6	Delmarva Power & Light Company	OS	"	N/A	N/A	N/A
7	Duke Power Company	OS	"	N/A	N/A	N/A
8	Duquesne Light Company	OS	"	N/A	N/A	N/A
9	East Kentucky Power Cooperative Inc.	OS	"	N/A	N/A	N/A
10	Entergy Power Inc.	OS	"	N/A	N/A	N/A
11	Florida Power & Light Company	OS	FERC 4	N/A	N/A	N/A
12	Florida Power Corporation	OS	FERC 1	N/A	N/A	N/A
13	GPU Service Corporation	OS	"	N/A	N/A	N/A
14	Illinois Power Company	OS	"	N/A	N/A	N/A

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this listing. Enter "Total" in column (a) as the last line of the schedule. Report subtotals and total for columns (g) through (k).

5. In column (c), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns(e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatthours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled on the last line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on page 401,line 24.

10. Footnote entries as required and provide exptanations following all required data.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
872,934	$3,960,158	$19,282,529		$23,242,687	1
2,246,813	3,729,745	45,526,709		49,256,454	2
25,063	120,724	651,397		772,121	3
2,388,087	268,384	50,882,870		51,151,254	4
9		424		424	5
1,403,549	29,076,103	29,745,032	454,826	59,275,961	6
359,825	178,239	6,956,962		7,135,201	7
230,303	319,776	4,271,726		4,591,502	8
2,153	23,653	94,909		118,562	9
118,406	62,800	2,817,061		2,879,861	10
94,556	71,511	2,159,404		2,230,915	11
74,973	2,100	1,958,525		1,960,625	12
224,044	4,144,773	9,347,217		13,491,990	13
94,063	714,146	2,237,056		2,951,202	14

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

IU - for intermediate-term service from a desgnated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

Line No.	Name of Company or Public Authority [Footnote Affiliations] (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Kentucky Utilities Company	OS	FERC 1	N/A	N/A	N/A
2	Long Island Lighting Company	OS	FERC 4	N/A	N/A	N/A
3	Metropolitan Edison	OS	FERC 1	N/A	N/A	N/A
4	Michigan Electric Coordinating System	OS	"	N/A	N/A	N/A
5	Nevada Power Company	OS	"	N/A	N/A	N/A
6	Northeast Utilities Service Company	OS	"	N/A	N/A	N/A
7	Northern Indiana Public Service Company	OS	"	N/A	N/A	N/A
8	Oglethorpe Power Corporation	OS	"	N/A	N/A	N/A
9	Ohio Edison Company	OS	"	N/A	N/A	N/A
10	Old Dominion Electric Cooperative	OS	"	N/A	N/A	N/A
11	Orange & Rockland Utilties Inc.	OS	"	N/A	N/A	N/A
12	Pacific Gas & Electric Company	OS	"	N/A	N/A	N/A
13	Pennsylvania Power & Light Company	OS	"	N/A	N/A	N/A
14	Pennsylvania Power & Light Company	OS	"	N/A	N/A	N/A

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this listing. Enter "Total" in column (a) as the last line of the schedule. Report subtotals and total for columns (g) through (k).

5. In column (c), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns(e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatthours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled on the last line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on page 401, line 24.

10. Footnote entries as required and provide exptanations following all required data.

Megawatthours Sold (g)	REVENUE			Total($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
2,541	$8,137	$55,347		$63,484	1
106,452	1,300,989	2,697,497		3,998,486	2
197		30,356		30,356	3
288,340	441,694	4,989,956		5,431,650	4
820		19,348		19,348	5
120,617	225,824	2,080,995		2,306,819	6
88,407	287,295	1,831,658		2,118,953	7
19,535	23,034	398,097		421,131	8
183,508	521,829	3,983,103		4,504,932	9
148,932	294,893	2,723,690		3,018,583	10
737,731	335,828	17,172,760		17,508,588	11
9,021		216,132		216,132	12
312,437	1,287,383	7,779,611		9,066,994	13
29		4,393		4,393	14

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

IU - for intermediate-term service from a desgnated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

Line No.	Name of Company or Public Authority [Footnote Affiliations] (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Potomac Electric Power Company	OS	FERC 1	N/A	N/A	N/A
2	Public Service Electric & Gas Company	OS	"	N/A	N/A	N/A
3	Rochester Gas & Electric Corporation	OS	FERC 4	N/A	N/A	N/A
4	San Diego Gas & Electric Company	OS	FERC 1	N/A	N/A	N/A
5	Seminole Electric Cooperative Incorp.	OS	FERC 4	N/A	N/A	N/A
6	South Carolina Electric & Gas	OS	FERC 1	N/A	N/A	N/A
7	Southern Company Services, Inc.	OS	"	N/A	N/A	N/A
8	Toledo Edison Company	OS	"	N/A	N/A	N/A
9	Union Electric Company	OS	"	N/A	N/A	N/A
10	United Illuminating Company	OS	"	N/A	N/A	N/A
11	Virginia Electric & Power Company	OS	"	N/A	N/A	N/A
12						
13	OTHER PUBLIC AUTHORITIES					
14	American Municipal Power-Ohio	OS	"	N/A	N/A	N/A

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this listing. Enter "Total" in column (a) as the last line of the schedule. Report subtotals and total for columns (g) through (k).

5. In column (c), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns(e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatthours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled on the last line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on page 401, line 24.

10. Footnote entries as required and provide exptanations following all required data.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
311,793	$585,684	$4,876,390		$5,462,074	1
1,687,001	2,344,241	38,475,728		40,819,969	2
820		22,548		22,548	3
1,640		35,497		35,497	4
33,885		755,123		755,123	5
7,319	1,328	176,006		177,334	6
162,147	698,742	4,311,530		5,010,272	7
14,263	18,500	236,083		254,583	8
18,879		697,229		697,229	9
410		11,374		11,374	10
1,714,361	1,616,515	35,203,687		36,820,202	11
					12
					13
100,281	307,438	1,722,619		2,030,057	14

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

IU - for intermediate-term service from a desgnated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

Line No.	Name of Company or Public Authority [Footnote Affiliations] (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	City of Tallahassee	OS	FERC 1	N/A	N/A	N/A
2	City of Vineland	OS	"	N/A	N/A	N/A
3	Jacksonville Electric Authority	OS	"	N/A	N/A	N/A
4	New York Power Authority	OS	"	N/A	N/A	N/A
5	Orlando Utilities Commission	OS	"	N/A	N/A	N/A
6	Sacramento Municipal Utility District	OS	"	N/A	N/A	N/A
7	South Carolina Public Service Authority	OS	"	N/A	N/A	N/A
8	South River Project (PSE&G)	OS	"	N/A	N/A	N/A
9	Tenneessee Valley Authority	OS	"	N/A	N/A	N/A
10						
11	OTHER NONUTILITIES					
12	AIG Trading Corporation	OS	FERC 1	N/A	N/A	N/A
13	Aquila Energy	OS	"	N/A	N/A	N/A
14	Catex Vitol Electric LLC	OS	"	N/A	N/A	N/A

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this listing. Enter "Total" in column (a) as the last line of the schedule. Report subtotals and total for columns (g) through (k).

5. In column (c), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns(e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatthours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled on the last line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on page 401,line 24.

10. Footnote entries as required and provide exptanations following all required data.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
27		$622		$622	1
334		7,192		7,192	2
154		3,426		3,426	3
178,538	164,910	3,310,963		3,475,873	4
1,578	21,420	35,296		56,716	5
4,088		79,108		79,108	6
104,129	337,362	2,128,957		2,466,319	7
50,674	31,504	1,034,463		1,065,967	8
402,463	680,346	7,809,442		8,489,788	9
					10
					11
7,458	17,376	174,579		191,955	12
138,182	214,918	3,713,645		3,928,563	13
52,483	153,588	1,152,570		1,306,158	14

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

IU - for intermediate-term service from a desgnated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

Line No.	Name of Company or Public Authority [Footnote Affiliations] (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Citizens Lehman Power Sales	OS	FERC 1	N/A	N/A	N/A
2	CNG Power Services Corporation	OS	"	N/A	N/A	N/A
3	Coastal Electric Services Company	OS	"	N/A	N/A	N/A
4	Coral Power LLC	OS	"	N/A	N/A	N/A
5	Delaware Municipal Electric Corporation	OS	"	N/A	N/A	N/A
6	Duke/Louis Dreyfus, LLC	OS	"	N/A	N/A	N/A
7	Dupont Power Marketing Inc.	OS	"	N/A	N/A	N/A
8	Eastex Power Marketing Inc.	OS	"	N/A	N/A	N/A
9	El Paso Energy Marketing Company	OS	"	N/A	N/A	N/A
10	Electric Clearinghouse Inc.	OS	"	N/A	N/A	N/A
11	Englehard Power Marketing Inc.	OS	"	N/A	N/A	N/A
12	Enron Power Marketing Inc.	OS	"	N/A	N/A	N/A
13	Equitable Power Services Company	OS	"	N/A	N/A	N/A
14	Heartland Energy Services	OS	"	N/A	N/A	N/A

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this listing. Enter "Total" in column (a) as the last line of the schedule. Report subtotals and total for columns (g) through (k).

5. In column (c), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns(e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatthours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled on the last line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on page 401,line 24.

10. Footnote entries as required and provide exptanations following all required data.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
132,673	$191,073	$3,254,522		$3,445,595	1
137,353	254,780	3,067,849		3,322,629	2
18,862	7,464	422,454		429,918	3
7,381	34,976	140,359		175,335	4
15,254		449,159		449,159	5
186,249	123,573	4,322,714		4,446,287	6
38,545	61,288	1,237,020		1,298,308	7
820	2,800	21,348		24,148	8
6,561	13,472	185,043		198,515	9
746,588	714,305	16,374,634		17,088,939	10
25,833		647,273		647,273	11
697,415	1,075,700	12,480,668		13,556,368	12
410		7,374		7,374	13
17,632	2,080	417,009		419,089	14

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

IU - for intermediate-term service from a desgnated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

Line No.	Name of Company or Public Authority [Footnote Affiliations] (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Illinova Power Marketing Inc.	OS	FERC 1	N/A	N/A	N/A
2	Koch Power Services Inc.	OS	"	N/A	N/A	N/A
3	LG&E Power Marketing Inc.	OS	"	N/A	N/A	N/A
4	Morgan Stanley Capital Group Inc.	OS	"	N/A	N/A	N/A
5	National Gas & Electric LP	OS	"	N/A	N/A	N/A
6	Natural Resources Group Inc.	OS	"	N/A	N/A	N/A
7	NorAm Energy Services	OS	"	N/A	N/A	N/A
8	Pacificorp Power Marketing	OS	"	N/A	N/A	N/A
9	PanEnergy Power Services Inc.	OS	"	N/A	N/A	N/A
10	Phibro, Inc.	OS	"	N/A	N/A	N/A
11	Sonat Power Marketing Inc.	OS	"	N/A	N/A	N/A
12	Transcanada Power Corporation	OS	"	N/A	N/A	N/A
13	US Gen Power Services	OS	"	N/A	N/A	N/A
14	Wabash Valley Power Association	OS	"	N/A	N/A	N/A

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this listing. Enter "Total" in column (a) as the last line of the schedule. Report subtotals and total for columns (g) through (k).

5. In column (c), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns(e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatthours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled on the last line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on page 401, line 24.

10. Footnote entries as required and provide exptanations following all required data.

Megawatthours Sold (g)	REVENUE			Total($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
1,640		$39,297		$39,297	1
13,861	15,632	323,289		338,921	2
43,916	109,736	955,302		1,065,038	3
16,710	31,896	361,346		393,242	4
4,511		92,416		92,416	5
	2,800			2,800	6
2,460	7,128	56,917		64,045	7
101,775		2,262,124		2,262,124	8
61,749	38,584	1,259,519		1,298,103	9
80,780	106,800	2,011,911		2,118,711	10
7,426	611,842	760,945		1,372,787	11
91,851	128,328	2,741,926		2,870,254	12
558	3,264	9,621		12,885	13
4,085	34,627	86,772		121,399	14

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

IU - for intermediate-term service from a desgnated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

Line No.	Name of Company or Public Authority [Footnote Affiliations] (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	PA-NJ-MD Interconnection	OS	PJM 1	N/A	N/A	N/A
2						
3	TOTAL					
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this listing. Enter "Total" in column (a) as the last line of the schedule. Report subtotals and total for columns (g) through (k).

5. In column (c), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns(e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatthours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled on the last line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on page 401, line 24.

10. Footnote entries as required and provide exptanations following all required data.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
934,833		$25,991,186		$25,991,186	1
					2
21,167,916	64,782,684	457,714,038	454,826	522,951,548	3
					4
					5
*					6
					7
					8
					9
					10
					11
					12
					13
					14

< Page 311.7 Line 6 Column G >

Wholesale purchases totaling 11,072,000 megawatthours were supplied to the Consumer Energy Services Group within PECO Energy Company to meet jurisdictional customer needs.

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnotes.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	$15,319,779	$12,933,211
5	(501) Fuel	207,621,409	190,423,328
6	(502) Steam Expenses	14,156,262	21,304,728
7	(503) Steam from Other Sources	0	0
8	(Less) (504) Steam Transferred--Cr.	0	0
9	(505) Electric Expenses	1,089,547	2,790,736
10	(506) Miscellaneous Steam Power Expenses	15,369,146	12,335,349
11	(507) Rents	1,480,496	19,434,256
12	(509) Allowance	32,084	0
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	$255,068,723	$259,221,608
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	$6,201,278	$6,108,557
16	(511) Maintenance of Structures	2,124,177	3,535,293
17	(512) Maintenance of Boiler Plant	31,648,290	33,000,571
18	(513) Maintenance of Electric Plant	7,476,295	12,507,286
19	(514) Maintenance of Miscellaneous Steam Plant	1,938,342	3,216,678
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	$49,388,382	$58,368,385
21	TOTAL Power Production Expenses--Steam Power (Enter Total of lines 13 and 20)	$304,457,105	$317,589,993
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	$79,929,682	$87,029,537
25	(518) Fuel	128,990,501	137,729,735
26	(519) Coolants and Water	7,713,760	8,539,581
27	(520) Steam Expenses	29,879,033	31,033,599
28	(521) Steam from Other Sources	0	0
29	(Less) (522) Steam Transferred--Cr.	0	0
30	(523) Electric Expenses	47,975	123,574
31	(524) Miscellaneous Nuclear Power Expenses	135,627,145	105,866,383
32	(525) Rents	17,928,187	18,398,608
33	TOTAL Operation (Enter Total of lines 24 thru 32)	$400,116,283	$388,721,017
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	$53,328,376	$27,118,604
36	(529) Maintenance of Structures	5,093,746	8,450,220
37	(530) Maintenance of Reactor Plant Equipment	50,902,423	45,758,032
38	(531) Maintenance of Electric Plant	33,329,261	30,653,450
39	(532) Maintenance of Miscellaneous Nuclear Plant	12,498,307	23,106,987
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	$155,152,113	$135,087,293
41	TOTAL Power Production Expenses--Nuclear Power (Enter total of lines 33 and 40)	$555,268,396	$523,808,310
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	$1,221,799	$1,023,414
45	(536) Water for power	1,330,946	963,727
46	(537) Hydraulic Expenses	1,543,065	1,537,168
47	(538) Electric Expenses	0	0
48	(539) Miscellaneous Hydraulic Power Generation Expenses	79,381	11,126
49	(540) Rents	(642,970)	(643,370)
50	TOTAL Operation (Enter Total of lines 44 thru 49)	$3,532,221	$2,892,065

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ELECTRIC OPERATION AND MAINTENANCE EXPENSES(Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$323,632	$475,897
54	(542) Maintenance of Structures	40,502	21,722
55	(543) Maintenance of Reservoirs, Dams, and Waterways	193,241	46,917
56	(544) Maintenance of Electric Plant	1,878,454	892,167
57	(545) Maintenance of Miscellaneous Hydraulic Plant	537,550	684,690
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	$2,973,379	$2,121,393
59	TOTAL Power Production Expenses-Hydraulic Power(Enter total of lines 50 and 58)	$6,505,600	$5,013,458
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	$789,627	$655,248
63	(547) Fuel	14,392,192	9,803,827
64	(548) Generation Expenses	487,395	560,234
65	(549) Miscellaneous Other Power Generation Expenses	810,690	378,704
66	(550) Rents	0	172,357
67	TOTAL Operation (Enter Total of lines 62 thru 66)	$16,479,904	$11,570,370
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	$878,952	$722,653
70	(552) Maintenance of Structures	130,849	1,012,901
71	(553) Maintenance of Generating and Electric Plant	3,465,800	2,705,983
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	128,883	120,835
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	$4,604,484	$4,562,372
74	TOTAL Power Production Expenses—Other Power (Enter Total of lines 67 and 73)	$21,084,388	$16,132,742
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	$476,317,609	$339,907,418
77	(556) System Control and Load Dispatching	6,828,488	7,897,380
78	(557) Other Expenses	(32,202,442)	(90,811,448)
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	$450,943,655	$256,993,350
80	TOTAL Power Production Expenses (Enter Total of lines 21,41,59,74,and 79)	$1,338,259,144	$1,119,537,853
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervison and Engineering	$3,113,248	$3,223,445
84	(561) Load Dispatching	5,027,036	2,897,216
85	(562) Station Expenses	(64,112)	1,125,368
86	(563) Overhead Lines Expenses	1,308,788	851,931
87	(564) Underground Lines Expenses	146,432	74,872
88	(565) Transmission of Electricity by Others	0	0
89	(566) Miscellaneous Transmission Expenses	10,515,984	3,484,899
90	(567) Rents	5,113,120	4,449,005
91	TOTAL Operation (Enter Total of lines 83 thru 90)	$25,160,496	$16,106,736
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	$75	0
94	(569) Maintenance of Structures	854,985	210,413
95	(570) Maintenance of Station Equipment	4,744,780	8,914,012
96	(571) Maintenance of Overhead Lines	5,689,999	5,347,696
97	(572) Maintenance of Underground Lines	1,041,902	1,764,357
98	(573) Maintenance of Miscellaneous Transmission Plant	2,041,897	120,970
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	$14,373,638	$16,357,448
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	$39,534,134	$32,464,184
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	$7,637,241	$5,104,590

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount For Previous Year (c)
104	3. DISTRIBUTION Expenses (Continued)		
105	(581) Load Dispatching	$6,027,769	$3,875,287
106	(582) Station Expenses	2,857,031	5,292,709
107	(583) Overhead Line Expenses	11,222,011	10,060,753
108	(584) Underground Line Expenses	4,510,006	6,065,579
109	(585) Street Lighting and Signal System Expenses	123,684	154,661
110	(586) Meter Expenses	112,060	871,437
111	(587) Customer Installations Expenses	2,431,694	2,414,563
112	(588) Miscellaneous Expenses	11,905,684	19,915,708
113	(589) Rents	6,012,880	6,071,887
114	TOTAL Operation (Enter Total of lines 103 thru 113)	$52,840,060	$59,827,174
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	$441,194	$5,527,350
117	(591) Maintenance of Structures	685,943	328,745
118	(592) Maintenance of Station Equipment	9,690,908	12,227,898
119	(593) Maintenance of Overhead Lines	44,984,270	36,822,864
120	(594) Maintenance of Underground Lines	20,151,670	13,031,030
121	(595) Maintenance of Line Transformers	1,131,281	318,241
122	(596) Maintenance of Street Lighting and Signal Systems	1,364,892	732,479
123	(597) Maintenance of Meters	90,356	318,440
124	(598) Maintenance of Miscellaneous Distribution Plant	1,253,775	774,971
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	$79,794,289	$70,082,018
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	$132,634,349	$129,909,192
127	4.CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	$253,349	$231,346
130	(902) Meter Reading Expenses	8,299,121	9,892,321
131	(903) Customer Records and Collection Expenses	41,171,407	37,371,007
132	(904) Uncollectible Accounts	87,534,340	65,261,836
133	(905) Miscellaneous Customer Accounts Expenses	230,534	6,836,990
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	$137,488,751	$119,593,500
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	$27,757	$6,816
138	(908) Customer Assistance Expenses	7,221,194	3,934,659
139	(909) Information and Instructional Expenses	1,917,009	856,371
140	(910) Miscellaneous Customer Service and Information Expenses	15,677,969	3,619,349
141	TOTAL Cust. Service and Informational Exp.(Enter Total of lines 137 thru 140)	$24,843,929	$8,417,195
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision	$71,679	$57,141
145	(912) Demonstrating and Selling Expenses	11,994,083	6,100,168
146	(913) Advertising Expenses	92,680	333,794
147	(916) Miscellaneous Sales Expenses	110,123	49,702
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	$12,268,565	$6,540,805
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	$72,807,920	$92,575,512
152	(921) Office Supplies and Expenses	84,561,681	92,397,314
153	(Less) (922) Administrative Expenses Transferred--Credit	511,159	0

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$17,672,866	$12,885,454
156	(924) Property Insurance	6,968,462	8,640,346
157	(925) Injuries and Damages	16,905,817	15,362,315
158	(926) Employee Pensions and Benefits	91,240,414	93,147,278
159	(927) Franchise Requirements	0	0
160	(928) Regulatory Commission Expenses	6,491,890	5,698,493
161	(929) (Less) Duplicate Charges--Cr.	3,432,502	3,637,681
162	(930.1) General Advertising Expenses	1,417,540	175,264
163	(930.2) Miscellaneous General Expenses	6,096,625	6,936,223
164	(931) Rents	3,777	11,065
165	TOTAL Operation (Enter Total of lines 151 Thru 164)	$300,223,331	$324,191,583
166	Maintenance		
167	(935) Maintenance of General Plant	$875,205	$242,406
168	TOTAL Administrative and General Expenses (Enter total of lines 165 thru 167)	$301,098,536	$324,433,989
169	TOTAL Electric Operation and Maintenance Expenses (Enter total of lines 80,100,126,134,141,148 and 168)	$1,986,127,408	$1,740,896,718

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.

2. If the respondent's payroll for the reporting period includes any special construction personel, include such employees on line 3, and show the number of such special construction employees in a footnote.

3. The number of employees assignable to the electric department from joint functions of combination utilities may be dete mined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1. Payroll Period Ended (Date) 12/31/96	
2. Total Regular Full-Time Employees	6,188
3. Total Part-Time and Temporary Employees	
4. Total Employees	6,188

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. lso report exchanges of electricity (i.e. transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column(b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis(i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliablility of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy,capacity, etc. and any settlements for imbalanced exchanges.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	ASSOCIATED UTILITIES					
2	Susquehanna Electric Co.	RQ	FERC 1	N/A	N/A	N/A
3						
4	NONASSOCIATED UTILITIES					
5	Allegheny Power Service Corp.	OS	FERC 1	N/A	N/A	N/A
6	American Electric Power	OS	"	N/A	N/A	N/A
7	Atlantic City Electric	OS	"	N/A	N/A	N/A
8	Baltimore Gas & Electric Company	OS	"	N/A	N/A	N/A
9	Carolina Power & Light Company	OS	"	N/A	N/A	N/A
10	Central Hudson Gas & Electric Corp.	OS	"	N/A	N/A	N/A
11	Central Illinois Public Service Co.	OS	"	N/A	N/A	N/A
12	CINergy Services Inc.	OS	"	N/A	N/A	N/A
13	Cleveland Electric Illuminating Co.	OS	"	N/A	N/A	N/A
14	Commonwealth Edison Company	OS	"	N/A	N/A	N/A

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote for each adjustment.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a

4. footnote for each adjustment.
In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is

5. provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non- coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in column (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement.Do not report net exchange.

7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l), Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy.If more energy was delivered than received, enter a negative amount. If the settlement amount (1) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.

8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on page 401, line 10. The total amount in column (h) must be reported as Exchange Received on page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on page 401, line 13.

9. Footnote entries as required and provide explanations following all required data.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
						0	1
2,372,031				23,622,925		23,622,925	2
							3
							4
646,774				30,817,012		30,817,012	5
2,259,748			813,993	64,523,020		65,337,013	6
150,780				4,005,542		4,005,542	7
57,771				1,766,647		1,766,647	8
1,746,107				31,834,537		31,834,537	9
634				22,222		22,222	10
9,767				210,508		210,508	11
107,443				2,448,295		2,448,295	12
13,620				245,910		245,910	13
5,975,994				101,885,210		101,885,210	14

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. lso report exchanges of electricity (i.e. transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column(b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis(i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliablility of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy,capacity, etc. and any settlements for imbalanced exchanges.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Consolidated Edison Co. of NY, Inc.	OS	FERC 1	N/A	N/A	N/A
2	Dayton Power & Light	OS	"	N/A	N/A	N/A
3	Delmarva Power & Light Co.	OS	"	N/A	N/A	N/A
4	Delmarva Power & Light (1)	OS	"	N/A	N/A	N/A
5	Duke Power Company	OS	"	N/A	N/A	N/A
6	Duquesne Light Company	OS	"	N/A	N/A	N/A
7	East Kentucky Power Cooperative Inc.	OS	"	N/A	N/A	N/A
8	Florida Power Corporation	OS	FERC 4	N/A	N/A	N/A
9	GPU Service Corp.	OS	FERC 1	N/A	N/A	N/A
10	Illinois Power Company	OS	"	N/A	N/A	N/A
11	Indiana-Michigan Power	OS	"	N/A	N/A	N/A
12	Kentucky Utilities Company	OS	"	N/A	N/A	N/A
13	Louisville Gas & Electric	OS	"	N/A	N/A	N/A
14	New York State Electric & Gas Corp.	OS	"	N/A	N/A	N/A

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote for each adjustment.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a

4. footnote for each adjustment.
In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is

5. provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non- coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in column (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement.Do not report net exchange.

7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l), Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy.If more energy was delivered than received, enter a negative amount. If the settlement amount (1) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.

8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on page 401, line 10. The total amount in column (h) must be reported as Exchange Received on page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on page 401, line 13.

9. Footnote entries as required and provide explanations following all required data.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
9,485				$761,246		$761,246	1
32,786				613,289		613,289	2
2,534				296,233		296,233	3
592				28,991		28,991	4
33,567				1,300,356		1,300,356	5
26,161				582,653		582,653	6
413,978			1,384,000	8,533,941		9,917,941	7
				9,099		9,099	8
700,410				18,330,909		18,330,909	9
3,544				57,751		57,751	10
3,379				69,665		69,665	11
9,371				181,969		181,969	12
212				4,566		4,566	13
51,601				1,003,242		1,003,242	14

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. lso report exchanges of electricity (i.e. transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. *In column(b), enter a Statistical Classification Code* based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis(i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliablility of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five *years or longer and "firm" means that service cannot* be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy,capacity, etc. and any settlements for imbalanced exchanges.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Niagara Mohawk Power Corp.	OS	FERC 1	N/A	N/A	N/A
2	Northeast Utilities Service Company	OS	"	N/A	N/A	N/A
3	Northern Indiana Public Service Co.	OS	"	N/A	N/A	N/A
4	Ohio Edison Co.	OS	"	N/A	N/A	N/A
5	Pacificorp	OS	"	N/A	N/A	N/A
6	Pennsylvania Power & Light	OS	"	N/A	N/A	N/A
7	Potomac Electric Power Co.	OS	"	N/A	N/A	N/A
8	Public Service Company of New Mexico	OS	"	N/A	N/A	N/A
9	Public Service Electric & Gas Co.	OS	"	N/A	N/A	N/A
10	Southern California Edison Company	OS	"	N/A	N/A	N/A
11	Southern Company Services Inc.	OS	"	N/A	N/A	N/A
12	Southwestern Electric Cooperative	OS	"	N/A	N/A	N/A
13	Virginia Electric & Power Company	OS	"	N/A	N/A	N/A
14						

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote for each adjustment.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a

4. footnote for each adjustment.
In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is

5. provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non- coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in column (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.

7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l), Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (1) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.

8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on page 401, line 10. The total amount in column (h) must be reported as Exchange Received on page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on page 401, line 13.

9. Footnote entries as required and provide explanations following all required data.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
50,468				$1,561,712		$1,561,712	1
25,475				623,840		623,840	2
11,747				216,253		216,253	3
11,753				234,673		234,673	4
47,705			25,000	948,416		973,416	5
262,875				7,219,603		7,219,603	6
1,395,173			2,115,750	33,471,169		35,586,919	7
217,724				3,492,199		3,492,199	8
3,041				395,252		395,252	9
845				22,229		22,229	10
26,992			26,400	513,337		539,737	11
43,034			557,811	1,118,342		1,676,153	12
147,403				5,209,079		5,209,079	13
							14

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. lso report exchanges of electricity (i.e. transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column(b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis(i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliablility of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy,capacity, etc. and any settlements for imbalanced exchanges.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	OTHER PUBLIC AUTHORITIES					
2	American Municipal Power-Ohio	OS	FERC 1	N/A	N/A	N/A
3	City of Tallahassee	OS	"	N/A	N/A	N/A
4	New York Power Authority	OS	"	N/A	N/A	N/A
5	Orlando Utilities Commission	OS	"	N/A	N/A	N/A
6	South Carolina Public Service Auth.	OS	"	N/A	N/A	N/A
7	Tennessee Valley Authority	OS	"	N/A	N/A	N/A
8						
9	OTHER NONUTILITIES					
10	AIG Trading Corporation	OS	FERC 1	N/A	N/A	N/A
11	Aquila Energy	OS	"	N/A	N/A	N/A
12	Catex Vitol Electric LLC	OS	"	N/A	N/A	N/A
13	Citizens Lehman Power Sales	OS	"	N/A	N/A	N/A
14	CNG Power Services Corporation	OS	"	N/A	N/A	N/A

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote for each adjustment.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a

4. footnote for each adjustment.
In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is

5. provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non- coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in column (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement.Do not report net exchange.

7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l), Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy.If more energy was delivered than received, enter a negative amount. If the settlement amount (1) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.

8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on page 401, line 10. The total amount in column (h) must be reported as Exchange Received on page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on page 401, line 13.

9. Footnote entries as required and provide explanations following all required data.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
							1
591				6,916		6,916	2
11,720			25,000	347,299		372,299	3
10,876				219,795		219,795	4
233,007			1,760,000	5,414,514		7,174,514	5
77,120			60,000	2,106,716		2,166,716	6
				29,337		29,337	7
							8
							9
9,186				242,038		242,038	10
57,317				1,441,838		1,441,838	11
31,057				941,217		941,217	12
557,660				12,089,831		12,089,831	13
16,313				403,256		403,256	14

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

PURCHASED POWER (Account 555)
(Including power exchanges).

1. Report all power purchases made during the year. lso report exchanges of electricity (i.e. transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column(b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis(i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliablility of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy,capacity, etc. and any settlements for imbalanced exchanges.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand(MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Coastal Electric Services Company	OS	FERC 1	N/A	N/A	N/A
2	Coral Power LLC	OS	"	N/A	N/A	N/A
3	Duke/Louis Dreyfus LLC	OS	"	N/A	N/A	N/A
4	Dupont Power Marketing Inc.	OS	"	N/A	N/A	N/A
5	Eastex Power Marketing Inc.	OS	"	N/A	N/A	N/A
6	El Paso Energy Marketing Co.	OS	"	N/A	N/A	N/A
7	Electric Clearinghouse Inc.	OS	"	N/A	N/A	N/A
8	Enron Power Marketing Inc.	OS	"	N/A	N/A	N/A
9	Heartland Energy Services	OS	"	N/A	N/A	N/A
10	Koch Power Services Inc.	OS	"	N/A	N/A	N/A
11	LG&E Power Marketing Inc.	OS	"	N/A	N/A	N/A
12	Midcon Power Services Corporation	OS	"	N/A	N/A	N/A
13	NorAm Energy Services	OS	"	N/A	N/A	N/A
14	Pacificorp Power Marketing	OS	"	N/A	N/A	N/A

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote for each adjustment.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a

4. footnote for each adjustment.
In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is

5. provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non- coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in column (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement.Do not report net exchange.

7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l), Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy.If more energy was delivered than received, enter a negative amount. If the settlement amount (1) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.

8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on page 401, line 10. The total amount in column (h) must be reported as Exchange Received on page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on page 401, line 13.

9. Footnote entries as required and provide explanations following all required data.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
35,478				$867,809		$867,809	1
13,515				288,461		288,461	2
14,244				353,975		353,975	3
16,894				388,576		388,576	4
845				26,429		26,429	5
38,857				826,524		826,524	6
41,391				1,137,450		1,137,450	7
368,029				9,545,566		9,545,566	8
6,335			9,600	157,416		167,016	9
59,526				1,512,236		1,512,236	10
9,292				232,997		232,997	11
26,608				541,407		541,407	12
845				17,549		17,549	13
59,974				1,227,004		1,227,004	14

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. lso report exchanges of electricity (i.e. transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column(b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis(i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliablility of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy,capacity, etc. and any settlements for imbalanced exchanges.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	PanEnergy Power Services Inc.	OS	FERC 1	N/A	N/A	N/A
2	Sonat Power Marketing Inc.	OS	"	N/A	N/A	N/A
3	Tenneco Energy Marketing Company	OS	"	N/A	N/A	N/A
4	Transcanada Power Corporation	OS	"	N/A	N/A	N/A
5						
6	Delaware Resource Managment Inc.	OS	FERC 1	N/A	N/A	N/A
7	Fizzano Brothers	OS	"	N/A	N/A	N/A
8	General Chemical Co.	OS	"	N/A	N/A	N/A
9	Grows Landfill	OS	"	N/A	N/A	N/A
10	Kimberly-Clark	OS	"	N/A	N/A	N/A
11	Merck, Sharp & Dohme	OS	"	N/A	N/A	N/A
12	Montenay Montgomery Ltd	OS	"	N/A	N/A	N/A
13	Philadelphia Thermal Corp.	OS	"	N/A	N/A	N/A
14	Pottstown Landfill	OS	"	N/A	N/A	N/A

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote for each adjustment.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a

4. footnote for each adjustment.
In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is

5. provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non- coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in column (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement.Do not report net exchange.

7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l), Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy.If more energy was delivered than received, enter a negative amount. If the settlement amount (1) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.

8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on page 401, line 10. The total amount in column (h) must be reported as Exchange Received on page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on page 401, line 13.

9. Footnote entries as required and provide explanations following all required data.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
2,788				$79,095		$79,095	1
38,857				1,186,924		1,186,924	2
72,645				2,096,535		2,096,535	3
18,584				459,033		459,033	4
							5
95				2,469		2,469	6
12				174		174	7
12,692				284,526		284,526	8
39,104				1,716,708		1,716,708	9
40,014				845,971		845,971	10
4,899				115,502		115,502	11
202,236				7,786,147		7,786,147	12
137,030				3,361,989		3,361,989	13
37,704				1,509,544		1,509,544	14

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. lso report exchanges of electricity (i.e. transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column(b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis(i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliablility of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy,capacity, etc. and any settlements for imbalanced exchanges.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Scott Paper Company	OS	FERC 1	N/A	N/A	N/A
2	Donald Silknitter	OS	"	N/A	N/A	N/A
3	Sun Refining & Marketing Co.	OS	"	N/A	N/A	N/A
4						
5	NONASSOCIATED UTILITIES					
6	PA-NJ-MD Interconnection (1)	OS	PJM-1	N/A	N/A	N/A
7						
8	TOTAL					
9	NOTE: (1) Borderline Interchange					
10						
11						
12						
13						
14						

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote for each adjustment.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a

4. footnote for each adjustment.
In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is

5. provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non- coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in column (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement.Do not report net exchange.

7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l), Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy.If more energy was delivered than received, enter a negative amount. If the settlement amount (1) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.

8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on page 401, line 10. The total amount in column (h) must be reported as Exchange Received on page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on page 401, line 13.

9. Footnote entries as required and provide explanations following all required data.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
18,408				$475,747		$475,747	1
54				55		55	2
185,948				(14,922,018)		(14,922,018)	3
							4
							5
2,529,593				75,993,656		75,993,656	6
						0	7
21,909,867	0	0	6,777,554	469,540,055	0	476,317,609	8
							9
							10
							11
							12
							13
							14

Name of Respondent PECO Energy Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(Including transactions referred to as "wheeling")

1. Report all transmission of electricity, i. e. wheeling, provided for other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column(b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column(d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:

LF - for long-term firm transmission service. "Long-term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.

Line No.	Payment By (Company or Public Authority) [Footnote Affiliations] (a)	Energy Received From (Company or Public Authority) [Footnote Affiliations] (b)	Energy Delivered To (Company or Public Authority) [Footnote Affiliations] (c)	Statistic Classification (d)
1	Delaware Resource Management Inc.	Delaware Resource Management Inc.	Atlantic City Electric Co.	LF
2	TOTAL			
3				
4				
5				
6				
7				
8	Agreement term through Sept. 5, 2016.			
9				
10				
11				
12				
13				
14				
15				
16				
17				

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as "wheeling")

OS - for other transmission service. Use this category *only for those services which cannot be placed in* the above-defined categories, such as all nonfirm transmission service, regardless of the length of the contract. Describe the nature of the service in a footnote.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

5. In column (e), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. *Report receipt and delivery locations for all single* contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column(h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				Megatthours Received (i)	Megatthours Delivered (j)	
FERC 55	DRMI Substation	PE-AE Interconnect.	75	426,825	426,825	1
				426,825	426,825	2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)

(Including transactions referred to as "wheeling")

8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity listed in column (a). If no monetary settlement was made, enter zero ("0") in column(n). Provide a footnote explaining the nature of the nonmonetary settlement, including the amount and type of energy or service rendered.
10. Provide total amounts in column (i) through (n) as the last line. Enter "TOTAL" in column (a) as the last line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered on page 401, lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total revenues($) (k+l+m) (n)	Line No.
	$2,300,568	$25,839	$2,326,407	1
0	2,300,568	25,839	2,326,407	2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

MISCELLANEOUS GENERAL EXPENSES (Account 930.2)(ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	$1,984,343
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Publishing and Distributing Information and Reports to Stockholders; Trustee, Registrar, and Transfer Agent Fees and Expenses, and Other Expenses of Servicing Outstanding Securities of the Respondent	2,056,688
5	Other Expenses (List items of $5,000 or more in this column showing the (1) purpose, (2) recipient and (3) amount of such items. Group amounts of less that $5,000 by classes if the number of items so grouped is shown)	
6	Directors Fees	$515,793
7	Employee Education	27,377
8	Employee Relocation Expenses	484,064
9	United Way	17
10	Miscellaneous	1,028,343
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	$6,096,625

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Accounts 403, 404, 405)

(Except amortization of acquisition adjustments)

1. Report in Section A for the year the amounts for: (a) Depreciation Expense (Account 403); (b) Amortization of Limited-Term Electric Plant (Account 404); and (c) Amortization of Other Electric Plant (Account 405).

2. Report in section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.

3. Report all available information called for in section section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of section C the type of plant included in any subaccounts used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional classifications and showing a composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average average remaining life of surviving plant.

If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited-Term Electric Plant (Acc 404) (c)	Amortization of Other Electric Plant (Acc 405) (d)	Total (e)
1	Intangible Plant		$11,992,051		$11,992,051
2	Steam Product Plant	51,302,930			51,302,930
3	Nuclear Production Plant	278,335,310		29,944,500	308,279,810
4	Hydraulic Production Plant--Conventional				0
5	Hydraulic Production Plant--Pumped Storage	3,054,217			3,054,217
6	Other Production Plant	6,684,018			6,684,018
7	Transmission Plant	13,665,837			13,665,837
8	Distribution Plant	55,502,853			55,502,853
9	General Plant	2,867,080			2,867,080
10	Common Plant--Electric	5,378,798			5,378,798
11	TOTAL	$416,791,043	$11,992,051	$29,944,500	$458,727,594

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report	Year of Report
PECO Energy Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 12/31/96	Dec. 31, 1996

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM PRODUCTION						
13							
14	311	75,065	75.00		8.34%	R3	12.00
15	312	381,164	45.00		8.82%	RC	11.00
16	314	97,494	50.00		8.39%	R3	12.00
17	315	25,520	75.00		9.99%	LA	10.00
18	316	7,876	70.00		9.01%	R1	11.00
19	SUBTOTAL	587,119					
20							
21	* NUCLEAR PRODUCTION						
22							
23	321	1,482,490	80.00		3.67%	S2	27.00
24	322	3,382,820	41.00		4.30%	SB	23.00
25	323	647,845	29.00		4.28%	S3	23.00
26	324	850,401	75.00		3.79%	SB	26.00
27	325	306,535	88.00		3.75%	S0	27.00
28	SUBTOTAL	6,670,091					
29							
30	HYDRAULIC PRODUCTION						
31							
32	331	10,118	57.00		5.70%	R4	18.00
33	332	20,111	73.00		5.62%	L3	18.00
34	333	15,608	83.00		5.87%	RA	17.00
35	334	5,870	55.00		6.08%	L2	16.00
36	335	1,017	90.00		5.48%	R3	18.00
37	336	333	100.00		5.48%	R3	18.00
38	SUBTOTAL	53,057					
39							
40	OTHER PRODUCTION						
41							
42	341	903	40.00		35.91%	L3	3.00
43	342	3,740	100.00		30.31%	S1	3.00
44	344	14,721	100.00		31.84%	LA	3.00
45	345	1,107	91.00		34.43%	R3	3.00
46	346	506	75.00		31.02%	S3	3.00
47	SUBTOTAL	20,977					
48							
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [x] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	TRANSMISSION PLANT						
13							
14	352**	10,288	50.00		3.45%	R5	29.00
15	353**	193,711	55.00		3.28%	S1	31.00
16	354	136,024	60.00		2.48%	RC	40.00
17	355	2,910	45.00		3.41%	L2	29.00
18	356**	67,144	55.00		3.16%	R3	32.00
19	357**	3,466	60.00		3.80%	R2	26.00
20	358	28,065	60.00		4.27%	R2	23.00
21	359	425	40.00		9.68%	S3	10.00
22	SUBTOTAL	442,033					
23							
24	DISTRIBUTION						
25	361	24,281	45.00		5.90%	L2	17.00
26	362	271,572	45.00		4.17%	L2	24.00
27	364	191,736	50.00		2.59%	R1	39.00
28	365	288,652	50.00		2.90%	L1	34.00
29	366	117,895	60.00		3.23%	R4	31.00
30	367	324,214	60.00		2.08%	RB	48.00
31	368	204,504	40.00		3.40%	RA	29.00
32	369.1(A)	31,225	45.00		3.59%	L2	28.00
33	369.2(B)	134,713	65.00		2.26%	L1	44.00
34	370.0(C)	142,582	31.00		4.47%	RB	22.00
35	370.2(D)	74	55.00		3.32%	L5	30.00
36	371	101	45.00		2.98%	O4	34.00
37	373.0(E)	11,216	17.00		7.29%	L1	14.00
38	373.1(F)	155	9.00		11.07%	O3	9.00
39	373.2(G)	7,714	15.00		4.90%	LA	20.00
40	373.3(H)	1,338	23.00		9.35%	LA	11.00
41	SUBTOTAL	1,751,972					
42							
43							
44							
45							
46							
47	** Excluding 25 Cycle.						
48							
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [x] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	GENERAL						
13							
14	390	24,542	50.00		2.87%	LB	35.00
15	391.1	2,775	20.00		5.58%	LA	18.00
16	391.2	2,839	20.00		5.97%	LA	17.00
17	391.3(I)	4,422	8.00		17.37%	R1	6.00
18	393	92	22.00		8.97%	L2	11.00
19	394	6,343	45.00		2.60%	R1	38.00
20	395.1(J)	13,805	32.00		3.89%	R4	26.00
21	395.2(K)	726	35.00		4.04%	S2	25.00
22	395.3(L)	295	47.00		3.30%	S6	30.00
23	397	7,258	35.00		3.68%	R3	27.00
24	398	961	22.00		5.11%	R3	20.00
25	SUBTOTAL	64,058					
26							
27	TOTAL ELECTRIC	9,589,307					
28							
29							
30	NOTES:						
31							
32	(A) SERVICES - AERIAL						
33	(B) SERVICES - UNDERGND						
34	(C) METERS						
35	(D) METER INSTALLATIONS						
36	(E) LUMINAIRES						
37	(F) AER. COND.-ST LIGHT						
38	(G) UNDGD COND-ST LIGHT						
39	(H) P.O.L. CONDUCTORS						
40	(I) COMPUTERS						
41	(J) LAB EQU.-TEST DIV.						
42	(K) LAB EQU.-METER DIV.						
43	(L) LAB EQU.-CHEM DIV.						
44	* (M) & (N)						
45							
46							
47							
48							
49							
50							

< Page 337 Line 21 Column a >

Effective October 1, 1996, the Company changed the estimated depreciable lives and mortality curves of certain electric plant, pursuant to the Company's petition for a declaratory accounting order which was approved by the PAPUC on February 22, 1996. The order approves a ten-year reduction of the terminal dates, for depreciation accrual purposes only, of Limerick Units No. 1 and 2 and associated common facilities.

< Page 337.2 Line 44 Column a >

FOOTNOTE (M) AND (N) EXPLANATIONS:

(M) Column (b) the depreciable plant base is asset balance at 1/1/yy plus average plant additions less 1/1 reserve balance to which a remaining life rate is applied to develop the 1996 accrual.

(N) Column (e) the applied depreciation rate percentage was developed using the remaining life accrual for 1996 compared to the depreciable net unrecovered plant.

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) Miscellaneous Amortization (Account 425) -- Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions -- Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430) -- For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) -- Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	Miscellaneous Amortization (Account 425)	0
2	TOTAL-425	0
3		
4	Miscellaneous Income Deductions	
5	Donations (Account 426.1)	
6	Community Welfare	2,137,487
7	Educational	399,918
8	Social and Cultural	1,501,777
9		
10	Life Insurance (Account 426.2)	
11	Supplemental Executive Retirement Plan	(50,410)
12		
13	Penalties (Account 426.3)	0
14		
15	Expenditures for Certain Civil, Political and	
16	Related Activities (Account 426.4)	2,162,847
17	Other Deductions (Account 426.5)	4,495,967
18		
19	TOTAL-426	10,647,586
20		
21		
22	Interest on Debt to Associated Companies (Acct 430)	4,037,016
23	TOTAL-430	4,037,016
24		
25	Other Interest Expense (Account 431)	
26	See Supplement Attached	80,580,363
27	TOTAL-431	80,580,363
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) Miscellaneous Amortization (Account 425) -- Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions -- Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430) -- For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) -- Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)		Amount (b)
1	DESCRIPTION	INTEREST RATE	
2	Supplement - Account 431		
3			
4	Customer Deposits	6.0%	748,745
5	Tax Assessments Past Due	Various	51,797
6	Commitment Fees - Revolv. Credit Agmt.	0.125%	667,501
7	Carrying Charges - Salem #1 & #2	12.4%	345,000
8	Gas Refunds Received from Suppliers	6.0%	301,203
9	Interruptible Sales Refunds & Profits	8.75% - 10.5%	2,610,175
10	Overcollections - Electric Cost Rate	8.75% - 10.5%	274,242
11	Short Term Debt	5.10% - 7.38%	11,080,196
12	Exp. Assoc. with Accts Rec. Financing	5.24% - 5.79%	24,837,542
13	Deferred Compensation	6.5% - 9.3%	1,025,568
14	Interest Exp. - Decommissioning Trust	-	8,182,993
15	Interest Exp. - Decommissioning Escrow	-	1,478,827
16	Guaranteed Int on Pref Sec (MIPS)	9.0%	19,912,500
17	Guaranteed Int on Pref Sec (TOPRS)	8.72%	6,810,731
18	Comm. Fees - Del,York, Salem Cty PC Rev Bonds		381,112
19	State Corp Loans Tax	0.4%	35,000
20	Letter of Cr. Fees - Mtgry Cty Series A&B	0.425%	536,321
21	Other		1,300,910
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to formal cases before a regulatory body, or cases in which such a body was a party.

2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number, and a description of the case.) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of year (e)
1	Pennsylvania Public Utility Commission				
2	General Assessment	5,835,254		5,835,254	
3					
4	Pennsylvania Consumer Advocate				
5	General Assessment	431,001		431,001	
6					
7	Federal Energy Regulatory Commission				
8	Annual Charges	1,298,897		1,298,897	
9					
10	Pennsylvania Small Business Advocate				
11	Assessment	96,520		96,520	
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	$7,661,672	0	$7,661,672	0

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.

4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.

5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CHARGED CURRENTLY TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3, End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
Electric	928	$4,933,827					1
Gas	1928	901,427					2
							3
Electric	928	198,498					4
Gas	1928	232,503					5
							6
Electric	928	1,298,897					7
							8
							9
Electric	928	60,668					10
Gas	1928	35,852					11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21
							22
							23
							24
							25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
[redacted]		$7,661,672	0	[redacted]	0	0	46

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. *Describe and show below costs incurred and accounts* charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others. (See definition of research, development, and demonstration in Uniform System of Accounts.)

2. Indicate in column (a) the applicable classification, as shown below. Classifications:

A. Electric R, D & D Performed Internally
- (1) Generation
  - a. *Hydroelectric*
    - i. Recreation, fish, and wildlife
    - ii. Other hydroelectric
  - b. *Fossil-fuel steam*
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) System Planning, Engineering and Operation
- (3) Transmission
  - a. Overhead
  - b. Underground
- (4) Distribution
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $5,000.)
- (7) Total Cost Incurred

B. *Electric, R, D & D Performed Externally*
- (1) Research Support to the Electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A. Electric R,D & D Performed Internally	
2	(1) GENERATION	
3	a. Hydroelectric	
4	ii. Other Hydroelectric	Hydroelectric R,D, & D under $5,000 (0)
5		
6	b. Fossil Fuel Steam	Eddystone Station R,D & D Project
7		Fossil Fuel Steam R,D & D Projects under $5,000
8		
9		
10	c. Internal Combustion or Gas Turbine	
11		
12	d. Nuclear	Peach Bottom and Limerick R,D, & D Projects
13		
14		
15		
16		
17	e. Unconventional Generation	Technology Transfer
18		Unconventional Generation R,D & D Projects Under $5,000
19		
20	(2) SYSTEM PLANNING, ENGINEERING AND OPERATION	System Planning, Engineering & Operation Projects Under $5,000
21		
22	(3) TRANSMISSION	
23	a. Overhead	Technology Transfer
24		Overhead Transmission R, D & D Projects Under $5,000
25		
26	b. Underground	
27		
28	(4) Distribution	Distribution R,D and D Projects Under $5,000
29		
30	(5) Environment	
31		
32	(6) Utilization and Other	Utilization & Other R, D & D Projects Under $5,000
33		
34		Total Performed Internally
35		
36		
37		
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A.(6) and B.(4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).

5. Show in column (g) the total unamortized accumulation of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
0					4
					5
36,209		512	36,209		6
6,264		506	6,264		7
					8
					9
0					10
					11
882,882		517	882,882		12
					13
					14
					15
					16
0					17
0			0		18
					19
0					20
					21
					22
0					23
0					24
					25
					26
					27
0					28
					29
0					30
					31
0			0		32
					33
925,355			925,355		34
					35
					36
					37
					38

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others. (See definition of research, development, and demonstration in Uniform System of Accounts.)

2. Indicate in column (a) the applicable classification, as shown below. Classifications:

A. Electric R, D & D Performed Internally
- (1) Generation
  - a. Hydroelectric
    - i. Recreation, fish, and wildlife
    - ii. Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) System Planning, Engineering and Operation
- (3) Transmission
  - a. Overhead
  - b. Underground
- (4) Distribution
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $5,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally
- (1) Research Support to the Electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	B. Electric R, D & D Performed Externally	
2		
3	(1) Research Support to ERC or EPRI	EPRI Dues
4		
5		
6		
7		
8		
9		
10		Total EPRI Dues
11		
12		EPRI Tailored Collaboration
13		
14		
15		
16		
17		Total EPRI Tailored Collaboration
18		
19		Total Performed Externally
20		
21		Unamortized Accumulation
22		
23		
24		TOTAL
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A.(6) and B.(4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).

5. Show in column (g) the total unamortized accumulation of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
	1,298,282	517	1,298,282		3
	205,212	560	205,212		4
	266,036	566	266,036		5
	1,162,871	580	1,162,871		6
	266,036	588	266,036		7
	868,117	930	868,117		8
					9
	4,066,554		4,066,554		10
					11
	113,000	557	113,000		12
	21,700	564	21,700		13
	86,800	584	86,800		14
	261,500	912	261,500		15
					16
	483,000		483,000		17
					18
	4,549,554		4,549,554		19
					20
			3,625	3,625	21
					22
					23
	5,474,909		5,478,534	3,625	24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [x] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	$109,216,467		
4	Transmission	5,016,643		
5	Distribution	21,920,675		
6	Customer Accounts	13,436,431		
7	Customer Service and Informational	12,728,179		
8	Sales	2,978,092		
9	Administrative and General	68,053,661		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	$233,350,148		
11	Maintenance			
12	Production	63,509,092		
13	Transmission	4,365,793		
14	Distribution	27,649,095		
15	Administrative and General	96,069		
16	TOTAL Maint. (Total of lines 12 thru 15)	$95,620,049		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	$172,725,559		
19	Transmission (Enter Total of lines 4 and 13)	$9,382,436		
20	Distribution (Enter Total of lines 5 and 14)	$49,569,770		
21	Customer Accounts (Transcribe from line 6)	13,436,431		
22	Customer Service and Informational(Transcribe from line 7)	12,728,179		
23	Sales (Transcribe from line 8)	2,978,092		
24	Administrative and General (Enter Total of lines 9 and 15)	$68,149,730		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	$328,970,197	$14,489,632	$343,459,829
26	Gas			
27	Operation			
28	Production--Manufactured Gas	198,163		
29	Production--Nat. Gas(Including Expl. and Dev.)			
30	Other Gas Supply	2,242,303		
31	Storage, LNG Terminaling and Processing	850,244		
32	Transmission	223,229		
33	Distribution	7,589,562		
34	Customer Accounts	1,941,488		
35	Customer Service and Informational	1,542,097		
36	Sales	313,826		
37	Administrative and General	3,650,582		
38	TOTAL Operation (Enter Total of lines 28 thru 37)	$18,551,494		
39	Maintenance			
40	Production--Manufactured Gas	17,358		
41	Production--Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing	341,942		
44	Transmission			
45	Distribution	5,217,002		
46	Administrative and General	107,830		
47	TOTAL Maint. (Enter Total of lines 40 thru 46)	$5,684,132		

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
	Gas			
48	Total Operation and Maintenance			
49	Production--Manufactured Gas (Enter Total of lines 28 and 40)	$215,521		
50	Production--Natural Gas (Including Expl. and Dev.) (Total of lines 29 and 41)	0		
51	Other Gas Supply (Enter Total of lines 30 and 42)	$2,242,303		
52	Storage, LNG Terminaling and Processing (Total of lines 31 and 43)	$1,192,186		
53	Transmission (Lines 32 and 44)	$223,229		
54	Distribution (Lines 33 and 45)	$12,806,564		
55	Customer Accounts (Line 34)	1,941,488		
56	Customer Service and Informational (Line 35)	1,542,097		
57	Sales (Line 36)	313,826		
58	Administrative and General (Lines 37 and 46)	$3,758,412		
59	TOTAL Operation and Maint. (Total of lines 49 thru 58)	$24,235,626	$924,870	$25,160,496
60	Other Utility Departments			
61	Operation and Maintenance			
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	$353,205,823	$15,414,502	$368,620,325
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	28,621,133	2,457,737	31,078,870
66	Gas Plant	11,934,004	1,024,790	12,958,794
67	Other			0
68	TOTAL Construction (Total of lines 65 thru 67)	$40,555,137	$3,482,527	$44,037,664
69	Plant Removal (By Utility Departments)			
70	Electric Plant	3,590,009	308,279	3,898,288
71	Gas Plant	731,553	62,819	794,372
72	Other			0
73	TOTAL Plant Removal (Total of lines 70 thru 72)	$4,321,562	$371,098	$4,692,660
74	Other Accounts (Specify):			
75	Other	10,970,778		10,970,778
76				0
77				0
78				0
79				0
80				0
81				0
82				0
83				0
84				0
85				0
86				0
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	$10,970,778		$10,970,778
96	TOTAL SALARIES AND WAGES	$409,053,300	$19,268,127	$428,321,427

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.

2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.

3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.

4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

1. INTANGIBLE PLANT	
Organization	$677,136
Other	52,323,792
GENERAL PLANT	
Land and Land Rights	8,440,775
Structures and Improvements	161,184,904
Office Furniture & Equipment	26,527,252
Transportation Equipment	26,415,916
Stores Equipment	1,734,585
Tools, Shop & Garage Equip.	13,835,646
Lab. Equipment	0
Power Operated Equip.	56,224
Communication Equip.	7,962,598
Misc. Equip.	1,816,650
Other Tangible	15,792,609
Total General Plant	263,767,159
Total Plant in Service	316,768,087

Allocation of Common Utility Plant by Department

DEPARTMENT	ALLOC %	ALLOC COMMON
Electric	87.13 %	$276,000,034
Gas	12.87 %	$ 40,768,053
Total	100.00 %	$316,768,087

2. BALANCE BEGINNING OF YEAR	87,805,364
DEPRECIATION FOR YEAR CHARGED TO:	
Transportation Clearing Account	2,735,802
Operating Expenses - Electric	11,964,575
Operating Expenses - Gas	1,766,818
Amorti. Intangible Plant	0
Total Depr. Accruals	16,467,196
Net Charges for Plant Retired	
Book Cost of Plant Retired	90,774
Cost of Removals	1,351,309
Salvage (Credit)	114,254
NET CHARGES FOR PLANT RETIRED	1,327,829
OTHER DEBITS	
Total Other Debits	0
OTHER CREDITS	
Total Other Credits	0
BALANCE END OF YEAR	102,944,731

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.

2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.

3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.

4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

ALLOCATION OF ACCUMULATED DEPRECIATION/AMORTIZATION
COMMON UTILITY PLANT TO DEPARTMENTS:

DEPARTMENT	ALLOC %	ALLOC COMMON
Electric	87.13 %	$89,695,744
Gas	12.87 %	$13,248,987
Total	100.00 %	$102,944,731

3. Depreciation Expenses - $16,467,196

4. NONE

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [x] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	Megawatt Hours (b)	Line No.	Item (a)	Megawatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	32,945,449
3	Steam	10,856,001	23	Requirements Sales for Resale (See instruction 4, page 311.)	-
4	Nuclear	24,372,853	24	Non-Requirements Sales For Resale (See Instruction 4, page 311.)	21,167,916
5	Hydro--Conventional		25	Energy Furnished Without Charge	
6	Hydro--Pumped Storage	1,539,618	26	Energy Used by the Company (Electric Department Only,Excluding Station Use)	37,649
7	Other	179,401	27	Total Energy Losses	2,476,478
8	(Less) Energy for Pumping	2,230,248	28	TOTAL(Enter Total of Lines 22 Thru 27) (MUST EQUAL LINE 20)	56,627,492
9	Net Generation (Enter Total of Lines 3 thru 8)	34,717,625			
10	Purchases	21,909,867			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received	426,825			
17	Delivered	426,825			
18	Net Transmission for Other (Line 16 minus Line 17)	0			
19	Transmission By Other Losses				
20	TOTAL (Enter Total of Lines 9, 10,14,18 and 19)	56,627,492			

MONTHLY PEAKS AND OUTPUT

1. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.

2. Report in column (b) the system's energy output for each month such that the total on line 41 matches the total on line 20.

3. Report in column (c) a monthly breakdown of the Non-Requirements Sales For Resale reported on line 24. Include in the monthly amounts any energy losses associated with the sales so that the total on line 41 exceeds the amount on line 24 by the amount of losses incurred (or estimated) in making the Non-Requirements Sales For Resale.

4. Report in column (d) the system's monthly maximum megawatt load (60-minute integration) associated with the net energy for the system defined as the difference between columns (b) and (c).

5. Report in columns(e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales For Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	5,010,750	1,785,020	5,605	4	7 pm
30	February	4,489,983	1,638,717	5,803	5	7 pm
31	March	5,139,015	1,992,100	5,273	8	7 pm
32	April	4,236,017	1,714,623	4,686	23	2 pm
33	May	4,310,740	1,601,632	6,101	20	5 pm
34	June	4,833,916	1,782,551	5,966	14	4 pm
35	July	4,944,589	1,704,906	6,360	9	5 pm
36	August	5,033,936	1,710,272	6,509	23	4 pm
37	September	4,489,844	1,590,773	6,203	9	4 pm
38	October	4,616,934	1,938,440	4,967	9	11 am
39	November	4,641,525	1,812,757	5,007	27	7 pm
40	December	4,880,243	1,896,125	5,395	20	6 pm
41	TOTAL	56,627,492	21,167,916			

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report on this page gas-turbine and internal combustion plants of 10,000 KW or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis,report the Btu content of the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (line 37) and average cost per unit of fuel burned (line 40) must be consistent with charges to expense accounts 501 and 547 (line 41) as show on line 19.
8. If more than one fuel is burned in a plant, furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: Eddystone (b)			Plant Name: Cromby (c)		
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)	Steam			Steam		
2	Type of Plant Construction(Conventional, Outdoor Boiler, Full Outdoor, Etc.)	Conventional			Semi Outdoor Boiler		
3	Year Originally Constructed	1960			1954		
4	Year Last Unit was Installed	1976			1955		
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	1,489.00			418.00		
6	Net Peak Demand on Plant -- MW (60 minutes)	1,391			360		
7	Plant Hours Connected to Load	8,320			7,333		
8	Net Continuous Plant Capability (Megawatts)						
9	When Not Limited by Condenser Water	1,359			358		
10	When Limited by Condenser Water	1,341			345		
11	Average Number of Employees	270			92		
12	Net Generation,Exclusive of Plant Use --KWh	4,326,180,000			1,197,039,000		
13	Cost of Plant: Land and Land Rights	2,413,382			55,350		
14	Structures and Improvements	126,585,474			38,441,321		
15	Equipment Costs	637,177,238			156,244,658		
16	Total Cost	$766,176,094			$194,741,329		
17	Cost per KW of Installed Capacity (line 5)	514.5574			465.8883		
18	Production Expenses: Oper. Supv. & Engr.	5,399,726			1,505,747		
19	Fuel	99,708,554			27,144,845		
20	Coolants and Water (Nuclear Plants Only)						
21	Steam Expenses	9,485,095			2,454,197		
22	Steam From Other Sources						
23	Steam Transferred (Cr.)						
24	Electric Expenses	159,410			489,329		
25	Misc. Steam (or Nuclear) Power Expenses	743,916			2,507,063		
26	Rents						
27	Allowances						
28	Maintenance Supervision and Engineering	5,065,825			157,559		
29	Maintenance of Structures	1,002,148			70,767		
30	Maintenance of Boiler (Or Reactor) Plant	15,228,276			4,860,450		
31	Maintenance of Electric Plant	1,538,332			921,557		
32	Maintenance Misc. Steam (or Nuclear) Plant	752,056			249,224		
33	Total Production Expenses	$139,083,338			$40,360,738		
34	Expenses per Net KWh	$0.0321			$0.0337		
35	Fuel: Kind (Coal,Gas,Oil,or Nuclear)	Coal	Gas	Oil	Coal	Gas	Oil
36	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-Mcf)(Nuclear-indicate)	Tons	MCF	Bbl.	Tons	MCF	Bbl.
37	Quantity (Units) of Fuel Burned	1,389,378	2,860,478	1,381,711	358,594	1,183,886	417,487
38	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if nuclear)	13,196	1,030,000	150,918	13,089	1,033,000	148,853
39	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year	$39.070	$3.820	$21.230	$37.990	$3.400	$20.670
40	Average Cost of Fuel per Unit Burned	$41.970	$3.820	$21.440	$43.610	$3.400	$20.870
41	Avg. Cost of Fuel Burned per Million Btu	$1.590	$3.709	$3.382	$1.666	$3.291	$3.338
42	Avg. Cost of Fuel Burned per KWh Net Gen	$0.013	$0.003	$0.007	$0.013	$0.003	$0.007
43	Average Btu per KWh Net Generation	8,476.000	681.000	2,024.000	7,842.000	1,022.000	2,180.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U.S. of A.accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching,and Other Expenses classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 548 and 549 on line 24 "Electric Expenses," and Maintenance Account Nos.553 and 554 on line 31 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. *For a plant equipped with combinations of fossil fuel steam,* nuclear steam, hydro, internal combustion or gas-turbine equipment,report each as a separate plant. However,if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit,include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development;(b)types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type,fuel used, fuel *enrichment type and quantity for the report period,and* other physical and operating characteristics of plant.

Plant Name: Schuylkill (d)			Plant Name: Delaware (e)			Plant Name: Keystone (f)			Line No.
Steam			Steam			Steam			1
Conventional			Semi Outdoor Boiler			Outdoor Boiler			2
1958			1953			1967			3
1958			1953			1968			4
190.00			313.00			393.00			5
175			238			366			6
1,486			2,226			8,784			7
									8
175			256			344			9
166			250			340			10
19			47			182			11
107,445,000			214,998,000			2,650,331,316			12
$295,741			$1,353,563			$894,388			13
7,000,332			16,312,070			15,561,550			14
35,641,142			52,154,097			91,470,851			15
$42,937,215			$69,819,730			$107,926,789			16
225.9853			223.0662			274.6228			17
23,569			487,992			833,249			18
3,304,535			8,835,096			38,043,813			19
									20
379,398			143,822			546,421			21
									22
									23
						247,369			24
124,466			328,460			2,373,399			25
						32,668			26
									27
(878)			248,410			227,828			28
113,448			181,777			413,640			29
1,593,719			1,869,449			3,726,864			30
1,936,326			1,170,668			805,821			31
12,339			250,542			348,115			32
$7,486,922			$13,516,216			$47,599,187			33
$0.0696			$0.0628			$0.0179			34
Oil			Oil			Coal	Oil		35
Bbl.			Bbl.			Tons	Bbl.		36
224,127			444,117			1,030,965	5,556		37
150,045			146,476			12,203	138,800		38
$14.730			$19.890			$36.500	$28.660		39
$14.740			$19.890			$36.630	$26.790		40
$2.340			$3.234			$1.501	$4.596		41
$0.031			$0.041			$0.014	0		42
13,146.000			12,708.000			9,494.000	12.000		43

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report on this page gas-turbine and internal combustion plants of 10,000 KW or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis,report the Btu content of the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (line 37) and average cost per unit of fuel burned (line 40) must be consistent with charges to expense accounts 501 and 547 (line 41) as show on line 19.
8. If more than one fuel is burned in a plant, furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: Conemaugh (b)	Plant Name: P. Bottom - PECO Shr (c)
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)	Steam	Nuclear
2	Type of Plant Construction(Conventional, Outdoor Boiler, Full Outdoor, Etc.)	Outdoor Boiler	Conventional
3	Year Originally Constructed	1970	1974
4	Year Last Unit was Installed	1971	1974
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	388.00	985.00
6	Net Peak Demand on Plant -- MW (60 minutes)	380	965
7	Plant Hours Connected to Load	8,522	8,784
8	Net Continuous Plant Capability (Megawatts)		
9	When Not Limited by Condenser Water	356	951
10	When Limited by Condenser Water	332	929
11	Average Number of Employees	216	790
12	Net Generation,Exclusive of Plant Use --KWh	2,360,007,171	7,259,521,000
13	Cost of Plant: Land and Land Rights	494,482	313,245
14	Structures and Improvements	16,996,722	141,174,790
15	Equipment Costs	148,017,726	585,753,510
16	Total Cost	$165,508,930	$727,241,545
17	Cost per KW of Installed Capacity (line 5)	426.5694	738.3162
18	Production Expenses: Oper. Supv. & Engr.	872,244	20,704,490
19	Fuel	28,929,295	45,463,246
20	Coolants and Water (Nuclear Plants Only)		
21	Steam Expenses	1,144,041	8,343,369
22	Steam From Other Sources		
23	Steam Transferred (Cr.)		
24	Electric Expenses	193,374	
25	Misc. Steam (or Nuclear) Power Expenses	2,917,161	22,584,765
26	Rents	36,458	840,539
27	Allowances		
28	Maintenance Supervision and Engineering	303,782	7,473,587
29	Maintenance of Structures	340,815	48,035
30	Maintenance of Boiler (Or Reactor) Plant	4,057,350	1,126,043
31	Maintenance of Electric Plant	962,349	2,466,239
32	Maintenance Misc. Steam (or Nuclear) Plant	339,957	10,522,996
33	Total Production Expenses	$40,096,826	$119,573,309
34	Expenses per Net KWh	$0.0169	$0.0164

Line No.	Item (a)	Conemaugh (b)			P. Bottom - PECO Shr (c)		
35	Fuel: Kind (Coal,Gas,Oil,or Nuclear)	Coal	Gas	Oil	Nuclear		
36	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-Mcf)(Nuclear-indicate)	Tons	MCF	Bbl.	Grams		
37	Quantity (Units) of Fuel Burned	902,906	48,976	3,612	1,196,095		
38	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if nuclear)	12,477	1,030,000	138,800	65		
39	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year	$29.700	$3.550	$27.500			
40	Average Cost of Fuel per Unit Burned	$29.380	$3.550	$25.420	$30.625		
41	Avg. Cost of Fuel Burned per Million Btu	$1.177	$3.447	$4.361	$0.470		
42	Avg. Cost of Fuel Burned per KWh Net Gen	$0.011	0	0	$0.005		
43	Average Btu per KWh Net Generation	9,547.000	21.000	9.000	10,730.000		

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U.S. of A.accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching,and Other Expenses classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 548 and 549 on line 24 "Electric Expenses," and Maintenance Account Nos.553 and 554 on line 31 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment,report each as a separate plant. However,if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit,include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development;(b)types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type,fuel used, fuel enrichment type and quantity for the report period,and other physical and operating characteristics of plant.

Plant Name: Salem (d)	Plant Name: Limerick (e)	Plant Name: Eddystone (f)	Line No.
Nuclear	Nuclear	Internal Combustion	1
Conventional	Conventional	Metal Enclosure	2
1977	1986	1967	3
1981	1990	1970	4
997.00	2,323.00	80.00	5
0	2,267	76	6
0	8,784	92	7
			8
954	2,256	76	9
942	2,220	62	10
615	784		11
(29,393,000)	17,142,725,000	3,999,000	12
$3,676,038	$7,903,504	$61,469	13
263,493,386	1,438,976,419	185,966	14
922,424,131	5,323,390,271	8,068,779	15
$1,189,593,555	$6,770,270,194	$8,316,214	16
1,193.1730	2,914.4512	103.9526	17
8,189,490	51,388,880	29,761	18
5,653,941	77,708,094	255,837	19
11,556	7,124,742		20
7,008,238	14,519,870		21
0			22
0			23
46,276	1,699	41,662	24
69,673,631	38,284,005		25
(1,988)	1,590,388		26
			27
38,939,702	6,947,134	67,430	28
4,361,196	416,621	24,152	29
30,335,137	19,325,870		30
12,025,215	18,815,477	128,004	31
(6,246,218)	6,111,341		32
$169,996,176	$242,234,121	$546,846	33
($5.7835)	$0.0141	$0.1367	34

Nuclear			Nuclear			Oil			35
Grams			Grams			Bbl.			36
0			2,876,003			10,034			37
0			64			139,857			38
						$25.480			39
0			$20.876			$25.480			40
0			$0.328			$4.340			41
0			$0.004			$0.064			42
0			10,690.000			14,739.000			43

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report on this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis, report the Btu content of the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (line 37) and average cost per unit of fuel burned (line 40) must be consistent with charges to expense accounts 501 and 547 (line 41) as show on line 19.
8. If more than one fuel is burned in a plant, furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: Delaware (b)	Plant Name: Schuylkill (c)
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)	Internal Combustion	Internal Combustion
2	Type of Plant Construction(Conventional, Outdoor Boiler, Full Outdoor, Etc.)	Metal Enclosure	Metal Enclosure
3	Year Originally Constructed	1967	1969
4	Year Last Unit was Installed	1970	1971
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	77.00	40.00
6	Net Peak Demand on Plant -- MW (60 minutes)	74	38
7	Plant Hours Connected to Load	103	74
8	Net Continuous Plant Capability (Megawatts)		
9	When Not Limited by Condenser Water	74	38
10	When Limited by Condenser Water	60	30
11	Average Number of Employees		
12	Net Generation,Exclusive of Plant Use --KWh	3,344,000	2,175,000
13	Cost of Plant: Land and Land Rights	74,934	1,048
14	Structures and Improvements	96,053	109,162
15	Equipment Costs	7,790,591	2,451,557
16	Total Cost	$7,961,578	$2,561,767
17	Cost per KW of Installed Capacity (line 5)	103.3971	64.0441
18	Production Expenses: Oper. Supv. & Engr.	29,662	29,662
19	Fuel	249,813	130,001
20	Coolants and Water (Nuclear Plants Only)		
21	Steam Expenses		
22	Steam From Other Sources		
23	Steam Transferred (Cr.)		
24	Electric Expenses	46,286	35,922
25	Misc. Steam (or Nuclear) Power Expenses		
26	Rents		
27	Allowances		
28	Maintenance Supervision and Engineering	49,625	49,143
29	Maintenance of Structures	7,455	7,047
30	Maintenance of Boiler (Or Reactor) Plant		
31	Maintenance of Electric Plant	38,196	28,016
32	Maintenance Misc. Steam (or Nuclear) Plant		
33	Total Production Expenses	$421,037	$279,791
34	Expenses per Net KWh	$0.1259	$0.1286
35	Fuel: Kind (Coal,Gas,Oil,or Nuclear)	Oil	Oil
36	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-Mcf)(Nuclear-indicate)	Bbl.	Bbl.
37	Quantity (Units) of Fuel Burned	9,242	5,708
38	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if nuclear)	139,869	138,236
39	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year	$27.010	$22.740
40	Average Cost of Fuel per Unit Burned	$27.010	$22.740
41	Avg. Cost of Fuel Burned per Million Btu	$4.600	$3.920
42	Avg. Cost of Fuel Burned per KWh Net Gen	$0.075	$0.060
43	Average Btu per KWh Net Generation	16,236.000	15,237.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U.S. of A.accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching,and Other Expenses classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 548 and 549 on line 24 "Electric Expenses," and Maintenance Account Nos.553 and 554 on line 31 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment,report each as a separate plant. However,if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit,include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development;(b)types of cost units used for the various components of fuel cost; and (c) any other *informative data concerning plant type,fuel used, fuel* enrichment type and quantity for the report period,and other physical and operating characteristics of plant.

Plant Name: Chester (d)	Plant Name: Falls (e)	Plant Name: Moser (f)	Line No.
Internal Combustion	Internal Combustion	Internal Combustion	1
Metal Enclosure	Metal Enclosure	Metal Enclosure	2
1969	1970	1970	3
1969	1970	1970	4
56.00	64.00	64.00	5
54	40	60	6
119	127	136	7
			8
54	60	60	9
39	48	48	10
			11
2,194,000	3,349,000	4,734,000	12
$6,036		$1,272	13
87,338	137,708	321,514	14
6,017,414	5,746,530	5,751,066	15
$6,110,788	$5,884,238	$6,073,852	16
109.1212	91.9412	94.9039	17
30,313	29,662	29,662	18
131,529	208,857	279,930	19
			20
			21
			22
			23
40,693	38,994	45,356	24
			25
			26
			27
49,201	50,477	48,490	28
9,181	12,502	9,379	29
			30
18,870	179,506	43,859	31
			32
$279,787	$519,998	$456,676	33
$0.1275	$0.1552	$0.0964	34
Oil	Oil	Oil	35
Bbl.	Bbl.	Bbl.	36
5,837	8,965	11,929	37
139,728	139,222	139,643	38
$22.500	$23.190	$23.450	39
$22.500	$23.190	$23.450	40
$3.830	$3.970	$4.000	41
$0.060	$0.062	$0.059	42
15,613.000	15,653.000	14,779.000	43

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report on this page gas-turbine and internal combustion plants of 10,000 KW or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis,report the Btu content of the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (line 37) and average cost per unit of fuel burned (line 40) must be consistent with charges to expense accounts 501 and 547 (line 41) as show on line 19.
8. If more than one fuel is burned in a plant, furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: Richmond (b)	Plant Name: Croyden (c)
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)	Internal Combustion	Internal Combustion
2	Type of Plant Construction(Conventional, Outdoor Boiler, Full Outdoor, Etc.)	Metal Enclosure	Metal Enclosure
3	Year Originally Constructed	1973	1974
4	Year Last Unit was Installed	1973	1974
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	132.00	546.00
6	Net Peak Demand on Plant -- MW (60 minutes)	130	464
7	Plant Hours Connected to Load	625	1,271
8	Net Continuous Plant Capability (Megawatts)		
9	When Not Limited by Condenser Water	132	477
10	When Limited by Condenser Water	96	370
11	Average Number of Employees	69	
12	Net Generation,Exclusive of Plant Use --KWh	19,750,000	135,267,000
13	Cost of Plant: Land and Land Rights	100,391	404,195
14	Structures and Improvements	547,053	3,517,273
15	Equipment Costs	11,630,756	71,404,715
16	Total Cost	$12,278,200	$75,326,183
17	Cost per KW of Installed Capacity (line 5)	93.0166	137.9600
18	Production Expenses: Oper. Supv. & Engr.	29,662	40,469
19	Fuel	1,352,273	11,463,543
20	Coolants and Water (Nuclear Plants Only)		
21	Steam Expenses		
22	Steam From Other Sources		
23	Steam Transferred (Cr.)		
24	Electric Expenses	108,633	108,633
25	Misc. Steam (or Nuclear) Power Expenses		
26	Rents		
27	Allowances		
28	Maintenance Supervision and Engineering	49,981	112,537
29	Maintenance of Structures	10,415	49,251
30	Maintenance of Boiler (Or Reactor) Plant		
31	Maintenance of Electric Plant	1,151,427	1,341,114
32	Maintenance Misc. Steam (or Nuclear) Plant		11,629
33	Total Production Expenses	$2,702,391	$13,127,176
34	Expenses per Net KWh	$0.1368	$0.0970

Line No.	Item (a)	Richmond (b)			Croyden (c)		
35	Fuel: Kind (Coal,Gas,Oil,or Nuclear)	Oil			Oil		
36	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-Mcf)(Nuclear-indicate)	Bbl.			Bbl.		
37	Quantity (Units) of Fuel Burned	53,049			436,196		
38	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if nuclear)	139,447			139,856		
39	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year	$25.520			$26.280		
40	Average Cost of Fuel per Unit Burned	$25.520			$26.280		
41	Avg. Cost of Fuel Burned per Million Btu	$4.360			$4.470		
42	Avg. Cost of Fuel Burned per KWh Net Gen	$0.069			$0.085		
43	Average Btu per KWh Net Generation	15,731.000			18,942.000		

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U.S. of A.accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching,and Other Expenses classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 548 and 549 on line 24 "Electric Expenses," and Maintenance Account Nos.553 and 554 on line 31 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment,report each as a separate plant. However,if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit,include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development;(b)types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type,fuel used, fuel enrichment type and quantity for the report period,and other physical and operating characteristics of plant.

Plant Name: Southwark (d)	Plant Name: Salem (e)	Plant Name: (f)	Line No.
Internal Combustion	Internal Combustion	*	1
Metal Enclosure	Metal Enclosure	*	2
1967	1971		3
1968	1971		4
74.00	18.00		5
72	0		6
93	0		7
			8
72	20		9
53	16		10
			11
3,830,000	0		12
$166,148			13
106,420			14
7,608,933	2,494,073		15
$7,881,501	$2,494,073		16
106.5067	138.5596		17
			18
259,837	16,033		19
			20
			21
			22
			23
17,608			24
	258		25
			26
			27
2,070			28
3,203			29
			30
26,393	353,149		31
			32
$309,111	$369,440		33
$0.0807			34
Oil	Oil		35
Bbl.	Bbl.		36
10,141	511		37
139,548	144,162		38
$25.620	$32.520		39
$25.620	$31.376		40
$4.370	$518.197		41
$0.068	$16.030		42
15,519.000	29,784.000		43

< Page 403.3 Line 1 Column f >

PEACH BOTTOM UNITS #2 & #3
The figures shown in col. (c) pg 402.1 represent PECO's share of capacities, output and expenses for Peach Bottom.
Line 39 is MBTU per gram of Uranium.

(a) The cost of power generated is the actual cost of operations as stated in the detailed production expenses in col. (c) pg 402.1.
(b) In 1973, the PECO Energy Company, and the operating company of the Peach Bottom Atomic Power Station Units #2 & #3, jointly owned by the company (42.49%), PSE&G (42.49%), Atlantic City Electric Co. (7.51%) and Delmarva Power and Light Co. (7.51%), executed a nuclear fuel procurement agreement and a nuclear energy contract with an independent fuel company which acquired and owns the nuclear fuel in the reactors and sells the energy to the Company until the contract is terminated by the parties. Under a separate agreement the owners are obligated to bear their proportionate share of all costs under the agreement and contract. The rates used in Lines 41, 42 and 43 are based on the monies paid to the independent fuel company and do not include any spent fuel storage charges.
(c) This plant contains two boiling water reactors with enriched U02 pellets contained within a Zircaloy cladding. At 12/31/96 Unit #2 contained 53,964,264 grams of uranium, with an enrichment of 2.28%, Unit #3 contained 53,958,348 grams of uranium, with an enrichment of 1.64%.

< Page 403.3 Line 3 Column f >

SALEM UNITS #1 and #2

The figures shown in col. d pg 403.1 represent PECO Energy's share of capacities, output and expenses. Line 39 is MBTU per gram of Uranium.

(a) The cost of power generated is the actual cost of operations as billed as stated in the production expenses in COL d pg 403.1.
(b) PSE&G, the operating company, has executed nuclear fuel procurement ageements with suppliers of uranium and associated services. Under a seperate agreement the Co-owners are obligated to bear their proportionate share of all costs. The Company's share of the station is 42.59%.
(c) This plant has pressurized water reactors with slightly enriched U02 pellets with a Zircaloy cladding. At 12/31/96, Unit 1 contained 36,659,206 grams of uranium with an enrichment of 1.89% and Unit 2 contained 37,136,554 grams of uranium with an enrichment of 2.55% (units did not generate in 1996).

LIMERICK UNITS #1 AND #2
This plant contains four boiling water reactors in commercial operation with enriched U02 pellets contained within Zircaloy cladding at 12/31/96, Unit #1 contained 128,707,968 grams of uranium with an enrichment of 2.09%. Unit #2 contained

126,582,597 grams of uranium with an enrichment of 1.31%.

KEYSTONE
The figures shown in col. f pg 403 represent PECO Energy Co's 20.99 % share of Keystone Station, a jointly owned station.
CONEMAUGH
The figures shown in col. b pg 402.1 represent PECO Energy Co's 20.72 % share of Conemaugh Station, a jointly owned station.
SCHUYLKILL
The figures shown in col. c pg 402.2 for Schuylkill Gas Turbines include one leased gas turbine with a maximum generator nameplate. The amount on line 17 represents the cost of one gas turbine owned by the Company plus costs associated with the installation of the leased gas turbine.

SALEM
The figures shown in col. e pg 403.3 represent PECO Energy Company's 42.59 share of Salem Gas Turbine, a jointly owned station.

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).

2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.

3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.

4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power. System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No.2356 Plant Name: Muddy Run (b)
1	Type of Plant Construction (Conventional or Outdoor)	Outdoor
2	Year Originally Constructed	1967
3	Year Last Unit was Installed	1968
4	Total Installed Capacity (Generator Name Plate Ratings in MW)	800.00
5	Net Peak Demand on Plant-Megawatts (60 minutes)	972
6	Plant Hours Connected to Load While Generating	8,636
7	Net Plant Capability (In megawatts):	880
8	Average Number of Employees	*
9	Generation Exclusive of Plant Use-KWh	1,539,618,000
10	Energy Used for Pumping-KWh	2,230,248,000
11	Net Output for Load (line 9 minus line 10)-KWh	(690,630,000)
12	Cost of Plant	
13	Land and Land Rights	$1,420,823
14	Structures and Improvements	17,537,157
15	Reservoirs, Dams, and Waterways	34,439,962
16	Water Wheels, Turbines, and Generators	27,350,885
17	Accessory Electric Equipment	10,593,500
18	Miscellaneous Powerplant Equipment	2,203,610
19	Roads, Railroads, and Bridges	997,676
20	TOTAL Cost (Enter Total of lines 13 thru 19)	$94,543,613
21	Cost per KW of installed Capacity (line 20 ÷ line 4)	118.1795
22	Production Expenses	
23	Operation Supervision and Engineering	107,000
24	Water for Power	1,254,000
25	Pumped Storage Expenses	1,540,000
26	Electric Expenses	
27	Misc. Pumped Storage Power Generation Expenses	104,000
28	Rents	
29	Maintenance Supervision and Engineering	76,000
30	Maintenance of Structures	41,000
31	Maintenance of Reservoirs, Dams, and Waterways	210,000
32	Maintenance of Electric Plant	1,878,000
33	Maintenance of Misc. Pumped Storage Plant	879,000
34	Production Exp. Before Pumping Exp. (Enter Total of lines 23 thru 33)	$6,089,000
35	Pumping Expenses	* 38,819,986
36	Total Production Expenses (Enter Total of lines 34 and 35)	$44,908,986
37	Expenses per KWh (Enter result of line 36 divided by line 9)	$0.0291

< Page 408 Line 8 Column b >

Average Number of Employees:
Muddy Run is unattended. The plant is designed to be operated by remote control by supervisory personnel of Conowingo Hydro Plant. This plant is operated by Susquehanna Electric Company a subsidiary of PECO Energy Company.

< Page 408 Line 35 Column b >

The Company's sources of pumping power are Limerick Generating Station and the PJM power pool.

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).

2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility,and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity-Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 Min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Schuylkill	1967	2.75	3	10,000	$291,377
2	Cromby	1967	2.75	3	28,000	792,651
3	Delaware	1967	2.75	3	8,000	320,387
4	Keystone	1968	2.30	2	452,000	217,112
5	Conemaugh	1970	2.30	2	261,000	203,964
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. *For nuclear, see instruction 11, page 403.*

4. If net peak demand for 60 minutes is not available, give that which is available, specifying period.

5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a *separate plant. However, if the exhaust heat from the gas turbine* is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost Per MW Inst Capacity (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Cost (In cents per million Btu) (l)	Line No.
$105,955	0	$980		oil	1065¢	1
288,236	0	1,264	617	oil	357¢	2
116,504	0	98		oil	92¢	3
94,397	0	21,638	40,290	oil	453¢	4
	0	11,138	26,183	oil	418¢	5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
								1
2493 MCM ACAR	2,248,147	5,986,135	8,234,282					2
2493 MCM ACAR	$5,754,080	$22,064,973	$27,819,053					3
2493 MCM ACAR	$1,458,643	$7,129,533	$8,588,176					4
2493 MCM ACAR	$144,077	$3,806,727	$3,950,804					5
		$5,933,800	$5,933,800					6
2493 MCM ACAR	$194,799	$2,106,282	$2,301,081					7
2493 MCM ACAR	$910,999	$5,566,427	$6,477,426					8
								9
2493 MCM ACAR	$93,458	$1,413,772	$1,507,230					10
2493 MCM ACAR	$2,073,926	$15,821,323	$17,895,249					11
2505MCM AACSR								12
2493 MCM ACAR	$385,267	$4,204,865	$4,590,132					13
2493 MCM ACAR	$1,924,850	$4,737,832	$6,662,682					14
								15
2493 MCM ACAR	$4,770,646	$9,465,910	$14,236,556					16
								17
2493 MCM ACAR	$5,170,859	$11,260,716	$16,431,575					18
2493 MCM ACAR	$240,836	$4,564,980	$4,805,816					19
								20
								21
2493 MCM ACAR	$4,444	$993,560	$998,004					22
2493 MCM ACAR	$1,165	$383,864	$385,029					23
2493 MCM ACAR	$1,991	$341,578	$343,569					24
								25
2493 MCM ACAR	0	$674,584	$674,584					26
2493 MCM ACAR	$378,059	$10,684,707	$11,062,766					27
2493 MCM ACAR			0					28
2493 MCM ACAR								29
2493 MCM ACAR	$1,407,752	$5,740,840	$7,148,592					30
								31
								32
								33
								34
								35
								36

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo., Da., Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column(e) is:(1) single pole,wood or steel;(2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f)and(g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle,3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines, report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)
1	LEASED BY PECO FROM PEPCO(1							
2	The Susq. Power Co.	PECO	220.00	220.00	ST	3.57	0	1
3	- 7990	East Nottingham Twp.			ST	3.62	0	1
4								
5								
6	OWNED BY PECO ENERGY							
7	Nottingham Sub -7001	Bradford Sub	220.00	220.00	ST	24.73	0	1
8	PEPCO	Bradford Sub						
9	West Nottingham Twp-7003		220.00	220.00	ST	25.00	0	1
10	Bradford Sub - 7004	Chichester Sub	220.00	500.00	ST	12.72	0	1
11					TS	6.22	0	1
12					HFW	0.12	0	1
13					WP	0.05	0	1
14	Chichester Sub-7005	Alantic City Elec. Co	220.00	220.00	TS	0.48	0	1
15			220.00	220.00	AT	2.70	0	1
16					ST	0.88	0	1
17	Chichester Sub-7006	Delmarva Power & Light Co.	220.00	220.00	AT (20)	0.65	0.09	1
18					TS (32)	1.80	0	1
19	Nottingham Sub -7008	Balt. Gas & Elect						
20		Co. Graceton, MD	220.00	220.00	ST	1.00	0	1
21					HFW	0.27	0	1
22					ST	17.95	0	1
23	PEPCO	Nottingham Sub						
24	West Nottingham TWP -7009		220.00	220.00	ST	0.18	0	1
25	Whitpain Sub - 7010	PA Power & Light Co.	220.00	220.00	ST	4.43	0	1
26		Towamencin Twp			TS	0.45	0	1
27						0.65	0	1
28	Chichester Sub -7011	Delmarva Power &	220.00	220.00	AT			
29		Light Co						
30	Buckingham Sub - 7012	PSE&G			ST (36)	1.89	0	1
31		Lamberville, NJ	220.00	220.00	ST	8.67	0	1
32								
33								
34								
35								
36					TOTAL			

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS (Continued)

7. *Do not report the same transmission line structure twice.* Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
795 MCM ACSR								1
795 MCM ACSR	$19,820	$163,857	$183,677					2
								3
								4
								5
								6
795 MCM ACSR	$402,914	$1,023,446	$1,426,360					7
								8
795 MCM ACSR	$3,437	$774,128	$777,565					9
2493 MCM ACAR	$907,330	$6,683,449	$7,590,779					10
								11
								12
1590 MCM ACSR								13
795 MCM ACSR								14
795 MCM ACSR	$193,891	$2,990,564	$3,184,455					15
851 MCM ACSR								16
1590 MCN ACSR		$3,030,410	$3,030,410					17
								18
								19
851 MCM ACSR	$224,287	$2,018,631	$2,242,918					20
795 MCM ACSR								21
795 MCM ACSR								22
								23
795 MCM ACSR		$23,335	$23,335					24
795 MCM ACSR	$53,161	$1,107,631	$1,160,792					25
								26
								27
1590 MCM ACSR		$311,605	$311,605					28
								29
								30
795 MCM ACSR	$101,210	$181,780	$282,990					31
								32
								33
								34
								35
								36

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column(e) is:(1) single pole, wood or steel;(2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f)and(g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle,3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)
1	OWNED BY PECO ENERGY							
2	Bradford Sub-7013	Plymouth Mtg Sub	220.00	220.00	ST	20.62	0	1
3			220.00	220.00	TS	1.84	0	1
4			220.00	220.00	TS	0.13	0	1
5			220.00	220.00	TS	0.02	0	1
6			220.00	220.00	ST	22.21	0	1
7			220.00	220.00	TS	0.37	0	1
8			220.00	220.00	TS	0.02	0	1
9	Plymouth Meeting Sta. -7014	Whitpain Sub	220.00	220.00	ST	10.24	0	2
10					AT	5.11	0	1
11								
12	Muddy Run Sub -7015	Peach Bottom Sub	220.00	220.00	ST (29)	5.41	3.08	2
13	Whitpain Sub - 7016	North Wales Sub	220.00	220.00	ST	0.05		1
14					AT	0.71		1
15					HFS	1.84		1
16					WFS	0.33		1
17					TS	0.60		1
18	Whitpain -7017	Waneeta Sub	220.00	220.00	AT	2.37	0	1
19		&			ST	0.20	0	1
20					TS	1.31	0	1
21		Whitemarsh Sub			WFS	0.52	0	1
22					WFS (7)	2.55	0	1
23					HFS (31)	0.53	0.38	1
24					HFS (25)	0.85	4.08	1
25					TS	0.03	0	1
26								
27	Plymouth Meeting -7020	Waneeta Sub	220.00	220.00	TS	6.25	0	1
28		&			TS	1.20	0	1
29		Whitemarch			TS	0.94	0	1
30					ST	3.28	0	1
31					HFS	6.13	0	1
32					U	1.86	0	1
33								
34								
35								
36					TOTAL			

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
795 MCM ACSR	1,363,660	3,644,798	5,008,458					1
795 MCM ACSR								2
1590 MDM ACSR								3
1000 MCM AL								4
795 MCM ACSR								5
795 MCM ACSR								6
1000 MCM AL								7
795 MCM ACSR	$211,643	$1,381,047	$1,592,690					8
1590 MCM ACSR								9
								10
1590 MCM ACSR	$37,272	$1,649,491	$1,686,763					11
								12
								13
1590 MCM ACSR	$11,096	$1,227,460	$1,238,556					14
								15
								16
1590 MCM ACSR	$175,130	$7,328,182	$7,503,312					17
795 MCM ACSR								18
795 MCM ACSR								19
1590 MCM ACSR								20
795 MCM ACSR								21
1590 MCM ACSR								22
795 MCM ACSR								23
1590 MCM ACSR								24
								25
1590 MCM ACSR	$2,130,908	$5,754,984	$7,885,892					26
1192.5MCMSSAC								27
795 MCM ACSR								28
1590 MCM ACSR								29
1590 MCM ACSR								30
2000 MCMCUPTC								31
								32
								33
								34
								35
								36

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column(e) is: (1) single pole, wood or steel; (2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines, report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)
1	Buckingham Sub - 7021	Byberry Sub	220.00	220.00	AT	11.91	0	1
2					HFS	5.61	0	1
3					WFS	2.82	0	1
4					TS	0.16	0	1
5					ST	31.77	0	1
6							0	1
7	Peach Bottom N. Sub -7022	Newlinville Sub	220.00	220.00	ST	1.30	0	1
8					U	0.34	0	1
9	Plymouth Meeting Sub	Parrish Sub	220.00	220.00	ST	1.85	0	1
10	- 7023				AT	5.37	0	1
11					HFS (12)	0	4.83	1
12					AT	0.03	0	1
13	Parrish Sub - 7024	Grays Ferry Sub	220.00	220.00	WFS	1.26	0	1
14					HFS (12)	1.20	0.23	1
15	Bradford Sub - 7025	Newlinville Sub	200.00	200.00	AT (2)	9.32	9.23	1
16					ST	0.07	0	1
17	Grays Ferry Sub - 7028	Schuylkill Sub	220.00	220.00	U	0.20	0	1
18					U	0.15		1
19	Master Sub - 7029	Parrish Sub	220.00	220.00	AT	0.01		1
20					HFS	0.05		1
21					WFS	0.14		1
22					ST	0.06		1
23					HFS	0	0.68	1
24	Waneeta Sub - 7030	Richmond Sub	220.00	220.00	TS	2.24		1
25					U	0.95		1
26					U	0.95		1
27	Richmond Sub - 7030	PSE&G Co near	220.00	220.00	ST	0.58		1
28		Camden, NJ						
29	Limerick 220KV Switchyar -2	Limerick 230KV Sub	220.00	220.00	TS	0.09		1
30	Limerick 500KV Sub - 7033	Limerick 230KV Sub	220.00	220.00	TS	0.45		1
31	Limerick 230KV Sub 7034	Cromby Sub	220.00	220.00	TS	15.09		2
32	Cromby Sub -7035	North Wales Sub	220.00	220.00	TS (26)	16.88	0.59	1
33								
34								
35								
36					TOTAL			

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
			0					1
1590 MCM ACSR	1,039,328	5,904,470	6,943,798					2
								3
1590 MCM ACSR								4
								5
2493 MCM ACSR								6
2505 MCM ACSR	$782,132	$8,191,573	$8,973,705					7
1250 MCMCUOFC								8
1590 MCM ACSR		$4,360,390	$4,360,390					9
								10
								11
795 MCM ACSR								12
1590 MCM ACSR	$140,444	$1,056,965	$1,197,409					13
								14
1590 MCM ACSR	$163,660	$2,676,456	$2,840,116					15
795 MCM ACSR								16
2500 MCMCUPTC	$5,793	$1,022,725	$1,028,518					17
2500 MCMCUPTC								18
1590 MCM ACSR		$933,319	$933,319					19
								20
								21
								22
								23
1500 MCM ACSR	$147,209	$4,745,151	$4,892,360					24
2500 MCMCUPTC								25
2500 MCMCUPTC								26
1590 MCM ACSR	$297,904	$1,014,494	$1,312,398					27
								28
1590 MCM ACSR		$182,282	$182,282					29
1590 MCM ACSR		$798,528	$798,528					30
1590 MCM ACSR	$769,115	$12,139,213	$12,908,328					31
1590 MCM ACSR	$60,562	$11,171,456	$11,232,018					32
								33
								34
								35
								36

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column(e) is:(1) single pole,wood or steel;(2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f)and(g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle,3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)
1	Crompy Sub - 7036	Plymouth Mtg. Sub	220.00	220.00	TS	14.01	0	1
2	North Phila. Sub. - 7040	Waneeta Sub	220.00	220.00	ST	0.04	0	1
3					ST (30)	0	0.18	1
4					WFS (27)	0.30	1.23	1
5					HFS (30)	0	0.29	1
6								
7	Master Sub - 7041	North Phila Sub	220.00	220.00	TS	0.01	0	1
8					TS (27)	2.56	0	1
9					HFS (27)	2.56	0	1
10					WFS	0.25	0	1
11								
12	Croydon Sub - 7042	Holmesburg Sub	220.00	220.00	TS	5.80	0	1
13		&			HFS (39)	0	9.32	1
14		Emilie Sub			AT	0.01	0	1
15					WFS	0.08		
16	Emilie - 7043	Croydon Sub	220.00	220.00	ST	0.08	0	1
17					TS	5.71	0	1
18	Croydon Sub - 7044	Cox's Corner Sub	220.00	220.00	ST	0.63	0	1
19					TS (40)	0.09	0.70	1
20	North Wales Sub -7045	Buckingham Sub	220.00	220.00	TS	7.89	0	1
21					ST	5.54	0	1
22	Whitpain Sub - 7046	Heaton Sub	220.00	220.00	TS	8.74	0	1
23					ST (28)	2.17	0	1
24					ST (42)	0	2.40	
25					ST (34)	0	0.53	1
26	Eddystone Sub-7049	Chichester Sub	220.00	220.00	TS (37)	5.80	0	1
27					TS	0	1.25	2
28	Concord Su-7050	Middletown Sub 220-25	220.00	220.00	TS	8.92	0	1
29	Eddystone Sub -7051	Grays Ferry Sub	220.00	220.00	HFS	1.21	0	1
30		&			TS	10.16	0	1
31		Island Rd Sub			ST	0.08	0	1
32					AT	0.01	0	1
33	Eddystone Sub - 7052	Grays Ferry Sub	220.00	220.00	AT	0.13	0	1
34					TS (34)	10.96	0	1
35					U	1.72		
36					TOTAL			

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
1590 MCM ACSR	$2,183,592	$4,657,951	$6,841,543					1
1590 MCM ACSR	86,840	724,429	811,269					2
795 MCM ACSR								3
								4
								5
								6
1590 MCM ACSR	$82,994	$937,278	$1,020,272					7
795 MCM ACSR								8
								9
795 MCM ACSR								10
								11
1590 MCM ACSR	$870,083	$9,644,518	$10,514,601					12
								13
								14
								15
1590 MCM ACSR		$3,591,660	$3,591,660					16
1590 MCM ACSR		$683,769	$683,769					17
795 MCM ACSR								18
1590 MCM ACSR								19
1590 MCM ACSR		$4,146,145	$4,146,145					20
1590 MCM ACSR								21
1590 MCM ACSR		$4,215,730	$4,215,730					22
1590 MCM ACSR								23
								24
								25
1590 MCM ACSR	$631,277	$5,200,612	$5,831,889					26
								27
1590 MCM ACSR		$8,145,442	$8,145,442					28
1590 MCM ACSR	$712,276	$13,017,844	$13,730,120					29
								30
								31
								32
1590 MCM ACSR	$7,242,741	$13,120,505	$20,363,246					33
								34
								35
								36

Name of Respondent	This Report Is:	Date of Report (Mo., Da., Yr.)	Year of Report
PECO Energy Company	(1) [x] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. *Do not report substation costs and* expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column(e) is:(1) single pole,wood or steel;(2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f)and(g) the total pole miles of each transmission line. Show in column (f) the pole miles of line *on structures the cost of which is reported for the line designated;* conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle,3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)
1	Grays Ferry Sub - 7053	Passyunk Sub	220.00	220.00	U	1.53	0	1
2	Heaton Sub-7054	Buckingham Sub	220.00	132.00	ST	0.61	0	1
3					WFS	4.52	0	1
4					HFS	0.90	0	1
5					TS	4.23	0	1
6					TS	0.08	0	1
7	Whitpain Sub-7055	Roxborough Sub &	220.00	220.00	AT (44)	0	5.04	1
8		North Phila Sub			ST	3.00	0	1
9					WFS	0.03	0	1
10					HFS (45)	1.17	0	1
11					HFS	0.51	0	1
12					TS	7.10	0	1
13	Heaton -7057	Woodbourne	220.00	220.00	TS	1.88	0	1
14					WFS	10.82	0	1
15								
16	Concord Sub - 7059	Clay Sub 220-01	220.00	220.00	ST	6.95	0	1
17								
18	Master Sub-7404	Callowhill Sub	132.00	132.00	U	2.94		1
19	Master Sub-7406	Callowhill Sub	132.00	132.00	U	2.56		1
20	Delaware Sub -7408	Callowhill Sub	132.00	132.00	U	2.01		1
21	Blue Grass Sub - 7416	Holmesburg Sub	132.00	132.00	WFS	2.70	0	1
22					ST (11)	3.32	0	1
23	Byberry Sub-7418	Blue Grass Sub	132.00	132.00	WFS	0.43	0	1
24					WP	0.29	0	1
25					TS	0.95	0	1
26					HFW	0.05	0	1
27					ST	7.14	0	1
28	Waneeta Sub - 7419	Blue Grass Sub	132.00	132.00	WFS	1.29	0	1
29					WP	0.34	0	1
30					TS	1.57	0	1
31					HFW	0.05	0	1
32					U	2.42	0	1
33								
34								
35								
36					TOTAL			

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line,and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
100 MCMCUPTC		$4,946,354	$4,946,354					1
795 MCM ACSR	202,087	6,605,243	6,807,330					2
								3
								4
1590 MCM ACSR								5
								6
1590 MCM ACSR	$197,825	$13,857,635	$14,055,460					7
								8
								9
								10
								11
								12
1590 MCM ACSR	$1,455,533	$14,700,328	$16,155,861					13
								14
								15
795 MCM ACSR	0	$703,428	$703,428					16
								17
1500 MCMCUPTC		$2,441,893	$2,441,893					18
1500 MCMCUPTC		$2,021,950	$2,021,950					19
1500 MCMCUPTC		$2,528,991	$2,528,991					20
795 MCM ACSR		$813,583	$813,583					21
								22
477 MCM ACSR	$370,838	$508,283	$879,121					23
795 MCM ACSR								24
								25
								26
								27
795 MCM ACSR	$626,374	$4,022,975	$4,649,349					28
477 MCM ACSR								29
								30
								31
								32
								33
								34
								35
								36

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column(e) is:(1) single pole,wood or steel;(2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f)and(g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle,3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines, report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)
1	Emilie Sub-7421	PSE&G Co	132.00	132.00	ST	14.31	0	1
2		Trenton,NJ						
3	Byberry Sub-7422	Emilie Sub	132.00	132.00	ST (3)	8.80	10.00	1
4	Delaware Sub-7426	Waneeta Sub	132.00	132.00	U	3.44	0	1
5	Plymouth Meeting Sub-7431	Llanerch Sub	132.00	132.00	WP	0.42	0	1
6					HFW	5.75	0	1
7					ST	1.26	0	1
8					WFS	1.95	0	1
9					HFS	0.22	0	1
10					TS	0.16	0	1
11					HFW	0.21	0	1
12					ST	2.30	0	1
13					TS	1.08	0	1
14					U	1.00	0	1
15	North Wales Sub-7432	Buckingham Sub	132.00	132.00	TS			
16					ST			
17					HFS			
18					HFW			
19	Cromby Sub-7433	North Wales Sub	132.00	132.00	ST	15.29	0	1
20					TS (41)	0.05	0.10	1
21					AT	0.68	0	1
22					HFW	0.01	0	1
23	North Wales Sub -7434	Heaton Sub	132.00	220.00	TS	63.00	0	1
24					(25)	3.63	0	1
25					(43)	7.35	0	1
26	Bradford Sub-7435	Lukens Steel 130-52	132.00	220.00	HFW	9.87		1
27	Newlinville Sub-7436	Middletown Sub 130-54	132.00	220.00	HFW	0.63		1
28	Plymouth Meeting Sub-7437	Lukens Steel 130-37	132.00	220.00	HFS	0.23		1
29					ST	0.31		1
30	Eddystone Sub-7440	Chichester Sub	132.00	132.00	ST	0.80	0	1
31					AT	0.70	0	1
32					WFS	0.18	0	1
33					TS (18)		4.42	1
34					U	0.38	0	1
35					U	0.09	0	1
36					TOTAL			

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
477 MCM ACSR	$311,776	$2,917,006	$3,228,782					1
795 MCM ACSR								2
477 MCM ACSR	$200,537	$442,150	$642,687					3
2000 MCMCUPTC		$1,740,335	$1,740,335					4
477 MCM ACSR								5
477 MCM ACSR	$349,763	$2,482,020	$2,831,783					6
477 MCM ACSR								7
477 MCM ACSR								8
477 MCM ACSR								9
477 MCM ACSR								10
795 MCM ACSR								11
795 MCM ACSR								12
795 MCM ACSR								13
200 MCMCUPTC								14
795 MCM ACSR	$672,317	$2,075,187	$2,747,504					15
795 MCM ACSR								16
795 MCM ACSR								17
795 MCM ACSR								18
795 MCM ACSR	$524,099	$1,066,733	$1,590,832					19
795 MCM ACSR								20
								21
795 MCM ACSR								22
1590 MCM ACSR		$103,667	$103,667					23
								24
								25
795 MCM ACSR		$842,537	$842,537					26
795 MCM ACSR		$59,036	$59,036					27
795 MCM ACSR		$182,102	$182,102					28
795 MCM ACSR								29
								30
								31
								32
795 MCM ACSR	$96,704	$2,031,870	$2,128,574					33
1750 MCMALOFC								34
								35
								36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [x] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column(e) is:(1) single pole,wood or steel;(2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f)and(g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle,3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines, report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)
1	Eddystone Sub-7441	Woodlyn Sub	132.00	132.00	ST	0.36	0	1
2					ST (33)	0	0.03	1
3					TS	0.21	0	1
4					TS (33)	0	0.82	1
5					U	0.54	0	1
6					U	0.38	0	1
7	Eddystone Sub - 7442	Llanerch Sub	132.00	132.00	HFS	1.13	2.78	1
8					WFS	3.64	0	1
9					U	4.15	0	1
10					ST	0.53	0	1
11					TS (4)	0	5.46	1
12					U	4.62	0	1
13					HFS	0.22	0	1
14	Eddystone 220 Sub -7443	Eddystone 132 Sub	132.00	132.00	WP	0.06	0	1
15					TS	0.01	0	1
16								
17	Eddystone Sub 7445	MasterSub	132.00	132.00	ST (6)	0	0.53	1
18					HFS (6)	0.11	0.22	1
19					WFS	0.11	0	1
20					HFS	0	12.86	1
21	Plymouth meeting Sub-7498	Montco RR 130-34	132.00	132.00	TS	0.92		1
22								
23								
24	Planebrook Sub 7101	Goshen Sub ~6901	66.00	66.00				
25			66.00	66.00				
26			66.00	66.00				
27	Goshen Sub - 7102	Middletown Sub 6902	66.00	66.00				
28			66.00	66.00				
29			66.00	66.00				
30	Richmond Sub-7104	Westmoreland Sub	66.00	66.00	U	6.27	0	1
31			66.00	66.00	U	6.61	0	1
32								
33								
34								
35								
36					TOTAL			

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
795 MCM ACSR	$295,609	$1,086,907	$1,382,516					1
								2
795 MCM ACSR								3
795 MCM ACSR								4
2000 MCMCUOTC								5
1750 MCMALOFC								6
								7
795 MCM ACSR								8
2000 MCMCUPTC	$115,221	$6,270,033	$6,385,254					9
795 MCM ACSR								10
								11
2000 MCMCUPTC								12
								13
1590 MCM ACSR		$72,019	$72,019					14
								15
								16
								17
795 MCM ACSR		$2,211,371	$2,211,371					18
								19
								20
477 MCM ACSR								21
								22
								23
		$1,938,579	$1,938,579					24
								25
								26
		$4,090,574	$4,090,574					27
								28
								29
2000 MCMALSD		$3,560,400	$3,560,400					30
1500 MCMCUPTC								31
								32
								33
								34
								35
								36

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column(e) is:(1) single pole,wood or steel;(2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f)and(g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle,3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines, report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)
1	Richmond Sub-7106	Byberry Sub	66.00	66.00	ST (10)	0.21	6.06	1
2					(24)	0	3.32	1
3					WFS	0.18	0	1
4					U	3.83	0	1
5					U	3.83	0	1
6			66.00	66.00	WFS	0	1.11	1
7	Richmond Sub -7112	Holmesburg Sub	66.00	66.00	HFS	2.37	0	1
8					HFS	0.04	0	1
9					WFS	0.29	0	1
10					U	1.29	0	1
11						0.28		1
12			66.00	132.00	HFS (14)	1.49	4.44	1
13					WFS (13)	0.18	0	1
14					U	0.25	0	1
15	Westmoreland Sub-7115	Master Sub	66.00	66.00	U	0.64	0	1
16					U	2.56	0	1
17					U	2.08		1
18					U	2.08		1
19								
20	Schuylkill Sub -7121	Penn Sub - 6621	66.00	66.00	U	1.23		1
21	Schuylkill Sub -7122	Master Sub	66.00	66.00	U	2.47	0	1
22					U	1.62		1
23	Schuylkill Sub-7123	Llanerch Sub	66.00	66.00	HFS (15)	0.32	3.15	1
24					WFS (2)	1.46	0	1
25					HFS (16)	0	0.18	1
26					ST	0.03	0	1
27			66.00	66.00	U	0.14	0	1
28					HFS (17)	0	0.78	1
29	Schuylkill Sub -7124	Island Road Sub	66.00	66.00	ST	3.89	0	1
30					U	0.65	0	1
31					U	0.02		1
32					U	0.65	0	1
33					WFS	1.34	0	1
34								
35								
36					TOTAL			

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
477 MCM ACSR	$9,946	$1,854,733	$1,864,679					1
500 MCM CU								2
								3
750 MCMCUPL								4
750 MCMCUPL								5
#4/0 CU								6
	$35,769	$2,774,050	$2,809,819					7
336 MCM ACSR								8
								9
1100 MCMCUOFC								10
								11
795 MDM ACSR								12
								13
2000 MCMCUPTC								14
1500 MCMCUPTC	$1,655	$3,215,497	$3,217,152					15
2000 MCMCUPTC								16
750 MCMCUPTC								17
750 MCMCUPTC								18
								19
2000 MDMCUPTC	0	$538,507	$538,507					20
1500 MCMCUPTC	$24,000	$3,481,773	$3,505,773					21
2000 MCMCUPTC								22
	$97,074	$823,797	$920,871					23
								24
795 MCM ACSR								25
								26
200 MCMCUPL								27
795 MDM ACSR								28
#2/0 CU	$325,794	$5,367,861	$5,693,655					29
700 MCMCUPTC								30
1000 MCMALSD								31
700 MCMCUPTC								32
								33
			0					34
								35
								36

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column(e) is:(1) single pole,wood or steel;(2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f)and(g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle,3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines, report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)
1	Upper Darby Sub-7125	Llanerch Sub 6657	66.00	66.00	WFS	2.12		2
2					U	0.14		1
3	Westmoreland Sub - 7126	Schuylkill Sub	66.00	66.00	U			
4	Schuylkill Sub -7127	Lombard Sub 6627	66.00	66.00	U	1.90		1
5	Schuylkill Sub -7128	Penn Sub 6628	66.00	66.00	U	1.25		1
6					U			
7					U			
8	Southwark Sub -7130	Schuylkill Sub	66.00	66.00	U	4.21	0	1
9					U	1.68	0	1
10					U	3.14	0	1
11	Southwark Sub -7131	Island Road Sub	66.00	66.00	U	4.40	0	1
12					U	2.58	0	1
13	Southwark Sub - 7132	Delaware Sub	66.00	66.00	U	4.12	0	1
14	Delaware Sub-7134	North Phila Sub	66.00	66.00	U	3.64	0	1
15	North Phila Sub -7135	Westmoreland Sub	66.00	66.00	U	1.61	0	1
16	Eddystone Sub 7141	Chester Sub	66.00	66.00	TS	2.93	0	1
17					AT	0.02	0	1
18					U	0.89	0	1
19					U	0.11	0	1
20					WFS	0.04	0	1
21	Woodlyn Sub-7142	Upper Darby Sub	66.00	66.00	U		0	1
22					U			
23					U			
24	Chester Sub -7144	Chichester Sub	66.00	66.00	TS	0.70	0	1
25					ST	0.36	0	1
26					AT (20)	0	1.24	1
27					U	0.35	0	1
28					U	2.78	0	1
29					WP	0.08	0	1
30	Chichester Sub -7145	Delaware Power & Light						
31	Chester Sub -7147	Woodlyn Sub	66.00	66.00	U	5.31	0	1
32	Island Rd Sub -7148	Eddystone Sub						
33	Eddystone Sub-7149	Tinicum Prop -6649	66.00	66.00	TS	0.43		2
34					WP	1.20		2
35					ST	0.57		2
36					TOTAL			

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
795 ACSR	0	$21,161	$21,161					1
								2
	$74	$62,421	$62,495					3
1000 MCM CU	0	$1,724,008	$1,724,008					4
1500 MCM CU	0	$388,595	$388,595					5
								6
								7
1500 MCMCUOFC	$48,579	$2,634,857	$2,683,436					8
1500 MCMCUOFC								9
1500 MCMCUOFC								10
1500 MCMCUOFC	$1,635	$2,112,158	$2,113,793					11
1500 MCMCUOFC								12
1500 MCMCUPTC		$926,604	$926,604					13
1500 MCMCUPTC		$1,463,564	$1,463,564					14
1500 MCMCUPTC		$462,096	$462,096					15
795 MCM ACSR	$295,477	$2,105,119	$2,400,596					16
795 MCM ACSR								17
1500 MCMCUPTC								18
1250 MCM ALSD								19
795 MCM ACSR								20
500 MCMCUOFC	0	$105,835	$105,835					21
1100 MCMCUOFC								22
1500 MCMCUOFC								23
795 MCM ACSR	$120,187	$1,716,512	$1,836,699					24
795 MCM ACSR								25
795 ACSR								26
1500 MCMCUPTC								27
1500 MCMCUPTC								28
795 MCM ACSR								29
	$42,625	$5,337	$47,962					30
1100 MCMCUOFC		$1,356,781	$1,356,781					31
	$1,769		$1,769					32
4/0 ACSR		$82,878	$82,878					33
4/0 ACSR								34
2/0 CU								35
								36

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column(e) is:(1) single pole,wood or steel;(2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f)and(g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle,3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)
1					WFS	0.31		2
2	Eddystone Sub - 7158	Tinicum Prop 6658	66.00	66.00	TS	1.38	0	1
3					TS	0.43		2
4					WP	1.20		2
5					ST	0.56		2
6					WFS	0.31		2
7	Schuylkill Sub- 7162	Lombard Sub 6632	66.00	66.00	U	1.90	0	1
8	Schuylkill Sub -7163	Lombard Sub 6633	66.00	66.00	U	2.10	0	1
9	Westmoreland Sub-7168	Whitemarsh Sub	66.00	132.00	TS (38)	0	0.63	2
10					ST	0.30	0	1
11					ST	0.25	0	2
12					ST (38)	0	4.31	2
13					HFS (38)	0	4.86	2
14					HFS	0.34	0	1
15	Plymouth Meeting Sub-7169	Westmoreland Sub	66.00	66.00	TS	1.51	0	1
16					ST (9)	4.86	0	2
17					U	0.08	0	1
18			66.00	66.00	HFS (8)	0	0.50	2
19			66.00	66.00	ST	2.97	0	1
20	Plymouth Meeting Sub 7171	Barbadoes Sub	66.00	66.00	ST			
21	Plymouth Meeting Sub - 7174	Cromby Sub	66.00	66.00	ST			
22					HFW			
23					WP			
24	Passyunk Sub -7177	Southwark Sub	66.00	66.00	U	3.14		1
25	Cromby Sub-7180	Moser Sub -6680	66.00	66.00	WP	3.30		1
26					HFW	2.80		1
27					ST	0.34		1
28					WP	0.60		1
29					TS	1.77		2
30					U	2.00		1
31	Cromby Sub -7181	Moser Sub 6681	66.00	66.00	ST	7.64		2
32					HFW	2.10		1
33					U	0.97		1
34								
35								
36					TOTAL			

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
2/0 CU								1
795 ACSR		653,403	653,403					2
4/0 ACSR								3
4/0 ACSR								4
2/0 CU								5
2/0 CU								6
1500 MDMOFCCU		$617,716	$617,716					7
1500 MCMOFCCU		$857,267	$857,267					8
795 MCM ACSR	$53,083	$2,869,554	$2,922,637					9
								10
500 MCM CU								11
								12
								13
795 MCM ACSR								14
795 MCM ACSR	$636,548	$2,706,503	$3,343,051					15
500 MCM CU								16
1250 MCMCUSD								17
795 MCM ACSR								18
795 MCM ACSR								19
	$1,510	$113,024	$114,534					20
		$68,636	$68,636					21
								22
								23
		$4,390,860	$4,390,860					24
4/0 CU		$566,157	$566,157					25
4/0 CU								26
336.4 ACSR								27
336.4 ACSR								28
336.4 ACSR								29
2000 MCM CU								30
336.4 ACSR		$390,585	$390,585					31
477 ACSR								32
1100 CUOFC								33
		$553,287	$553,287					34
								35
								36

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column(e) is:(1) single pole, wood or steel;(2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f)and(g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle,3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)
1	Island Road Sub -7185	Sharon Hill Sub 6645	66.00	66.00	U	1.61		1
2					TS	1.01		1
3					WFW	0.26		1
4					ST	0.04		1
5					WP	0.09		1
6	Bradford Sub-7190	Cromby Sub	66.00	66.00				
7								
8	Schuylkill Gen. Sta-7301	Schuylkill Sub	13.20	13.20	U	0.07	0	3
9								
10			13.20	13.20	MSCL	0.10	0	1
11	Chester Station -7308	Chester Sub	13.20	13.20	U			
12	Delaware Gen. Sta. -7309	Delaware Sub	13.20	13.20	U	0.07	0	1
13					MEB	0.05	0	1
14	Richmond Gen. Sta. -7310	Richmond Sub	13.20	13.20	U	0.18	0	2
15	Southwark Station -7312	Southwark Sub	13.20	13.20	U			1
16	Delaware Station-7320	Richmond Reg	13.20	13.20	U			1
17	Richmond Station -7321	Richmond Reg	13.20	13.20	U			1
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,092.72	111.93	345

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
								1
								2
								3
								4
								5
	$136,357		$136,357					6
								7
2000 MCMCU		$368,515	$368,515					8
2500 MCM CU								9
1500 MCM AL		$302,810	$302,810					10
1750 MCMCU								11
2250 MCM CU		$395,215	$395,215					12
6980 MCMCUBAR								13
1500 MCM CU		$79,693	$79,693					14
1750 MCMCU		$256,536	$256,536					15
3 X 350 MCMCU		$159,730	$159,730					16
350 MCM CU		$885	$885					17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
				$1,455,220	$6,731,901	$5,113,120	* $13,300,241	33
								34
								35
	$55,466,472	$419,357,820	$474,824,292	$1,455,220	$6,731,901	$5,113,120	$13,300,241	36

< Page 422 Line 1 Column b >

Transmission Line Statistics

Footnotes

(1) Leased from subsidiary PECO Energy Power Co., under agreement of 2/20/26, as modified by Federal Power Commission Order dated 11/7/51 in Docket No. E-6155.

(2) 9.32 miles on structures of same plant designation. The towers for this length are double circuit structures.

(3) On structures of line extending from Emilie Transmission substation to a point of connection with PSE&G near Biles Island.

(4) Supporting structures owned by Penn Central Railroad Co.. Occupancy by PECO Energy Co. in accordance with agreement dated 7/12/57.

(5) Supported on structures owned by Penn Central Railroad Co. Occupancy by PECO Energy Co. in accordance with agreement dated 6/25/58.

(6) On structures of the line extending from Eddystone Transmission substation to Llanerch Transmission Subst.

(7) 2.49 miles of this line on PECO Energy Co. single steel columns are covered by a rental agreement with the Reading Railway Co. dated 6/11/62 for joint use of right of way.

(8) Supporting structures owned by Conrail. Occupancy by PECO Energy Co. in accordance with agreement dated 7/1/58.

(9) On structures of line extending from Waneeta Transmission Substation to Blue Grass Transmission Substation.

(10) 3.15 miles of right of way leased form Penn Central Railroad Co. in accordance with agreement dated 2/3/47. Byberry to Blue Grass Line - .445 miles. Richmond to Blue Grass Line - 2.705 miles.

(11) Supported on structures owned by Penn Central Railroad Co..

Occupancy by PECO Energy Co. in accordance with agreement dated 7/1/68.

(12) Supporting structures owned by Penn Central Railroad Co.. Occupancy by PECO Energy Co. in accordance with agreement dated 11/23/32.

(13) Supported on structures owned by Penn Central Railroad Co. Occupancy by PECO Energy Co. in accordance with agreement dated 11/12/56.

(14) Supported on structures owned by Penn Central Railroad Co.. Occupancy by PECO Energy Co. in accordance with agreement dated 5/17/40.

(15) 0.98 miled of this line are on structures owned by PECO Energy Co. but located on Penn Central Railroad Co. right of way. Included in agreement dated 5/17/40.

(16) This line is composed of 130 wood poles and 114 two-pole H frame wood poles. As these are intermixed, it is impossible to allocated pole-miles of line by structure type.

(17) Supporting structures owned by Penn Central Railroad Co.. Occupancy by PECO Energy Co. in accordance with agreement dated 12/17/58.

(18) Agreements among owning companies filed as supplements No. 19 and 20. Rate schedule FPC No. 30 effective 2/1/70. 28.03 miles are owned by PECO Energy Co., this represents 22% of the circuit miles in Pennsylvania.

(19) On structures of line extending from Chichester Transmission Substation to Atlantic City Electric Co..

(20) Construction and other cost - Overhead.

(21) Construction and other cost - Underground.

(22) Occupying a common right of way. All costs not separable are included with Nottingham to Plymouth Meeting Substation line.

(23) On structures of line extending from Byberry Substation to Blue Grass Substation.

(24) 4.08 miles of supporting structures owned by Reading Railway Co.. Occupancy by PECO Energy Co. in accordance with agreement dated 6/11/62. 0.49 miles of supporting structures owned by Penn Central Railroad. Occupancy by PECO Energy Co. in accordance with agreement dated 12/23/57 with the Penn Central Railroad Co..

(25) On structures of line extending from Whitpain Substation to North Wales Substation.

(26) 3.9 miles of supporting structures owned by Penn Central Railroad Co.. Occupancy by PECO Energy Co. in accordance with

agreement dated 12/23/57.

(27) On structures of line extending from Whitpain Substation to Waneeta Substation and Whitemarsh Substation.

(28) 3.08 miles on structures of the same Plant Designation. The towers for the length are double circuit structures.

(29) On structures of line extending from Whitpain Substation to Waneeta Substation.

(30) 10.38 miles on right of way of Reading Railway Co. under agreement dated 2/8/68.

(31) Structures on right of way of Penn Central Railroad Co.. Occupancy by PECO Energy Co. in accordance with agreement in negotiation.

(32) On structures of line extending from Eddystone Substation to Chichester Substation.

(33) On right of way of Baltimore and Ohio Railroad Co. east side of Schuylkill River by agreement dated 10/1/70.

(34) Agreements among owning Companies filed as Rate Schedule FPC No. 35, effective 7/16/71. This represents 42.55% of the circuit miles.

(35) On structures of line extending from Chichester Substation to Delmarva Power & Light Co..

(36) On structures of line extending from Grays Ferry Substation to Eddystone Substation.

(37) On structures of line extending from Plymouth Meeting Substation to Waneeta Substation.

(38) Supporting structures owned by Penn Central Railroad Co.

(39) On structures of line extending from Emilie Substation to Croydon Substation.

(40) On structures of 220kv line extending from Cromby Substation to North Wales Substation.

(41) On structures of 220kv line extending from North Wales Substation to Buckingham Substation.

(42) On structures of line extending from Whitpain Substation to Heaton Substation.

(43) On structures of line extending from Whitpain Substation to Plymouth Meeting Substation.

(44) 0.51 miles on structures owned by the Southeastern Pennsylvania Transportation Authority.

(45) The 1996 installation involved PECO assuming ownership of the existing Sun Oil owned wood pole line and extension of the line on steel poles to the new PECO owned Bluebell Substation.

(46) In 1990 the line was re-established as a 66 Kv sub-transmission line by Delaware Divsion (now Delchester Region) to feed the Sun Oil Marcus Hook co-generation facility.

(47) The existing underground 66 Kv cable from Chichester Substation to Chichester Terminal Yard from that point the line was installed on new wood poles to the Sun Refinery property line.

< Page 423.11 Line 33 Column p >

Transmission Line O&M expenses shown in columns (m) - (p) on page 423.11 are not readily available on a transmission line basis. The amounts shown on page 423.11 consist of FERC Accounts 563, 564, 567, 571 and 572 for the year ended 12/31/96.

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Bucks Division (Distribution)	*			
2	AQUE	D/U	35.00	4.36	
3	Bellevue	D/U	35.00	4.36	
4	Bellevue	D/U	35.00	13.80	
5	Big Oak	D/U	35.00	4.36	
6	Birch	D/U	35.00	4.36	
7	Bristol	D/U	35.00	4.36	
8	Bristol	D/U	35.00	13.80	
9	Broadale	D/U	35.00	4.36	
10	Buckingham	D/U	230.00	35.00	
11	Canal	D/U	35.00	4.36	
12	Carver	D/U	35.00	4.36	
13	Chalfont	D/U	35.00	4.36	
14	Chalfont	D/U	35.00	4.36	
15	Church	D/U	35.00	4.36	
16	Commons	D/U	35.00	4.36	
17	Cross	D/U	35.00	4.36	
18	Croydon	D/U	230.00	13.60	
19	Curly	D/U	35.00	4.36	
20	Danboro	D/U	35.00	4.36	
21	Doylestown	D/U	35.00	4.36	
22	Durham	D/U	35.00	4.36	
23	Eddington	D/U	230.00	13.60	
24	Edgely	D/U	35.00	4.36	
25	Ellwood	D/U	35.00	4.36	
26	Emilie	D/U	230.00	13.80	
27	Emilie	D/U	230.00	35.00	
28	Emilie	D/U	35.00	4.36	
29	Emilie	D/U	35.00	4.36	
30	Eureka	D/U	35.00	4.36	
31	Fairless	D/U	35.00	4.36	
32	Falls	D/U	138.00	35.00	
33	Falls	D/U	138.00	35.00	
34	Falls	D/U	35.00	13.80	
35	Falls	D/U	35.00	4.36	
36	Folly	D/U	35.00	4.36	
37	Gardenville	D/U	35.00	4.36	
38	Gravel	D/U	35.00	4.36	
39					
40	Hartsville	D/U	35.00	4.36	

SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
1.50	1					2
5.00	2					3
5.00	1					4
12.50	5					5
1.50	1					6
5.00	2					7
5.00	1					8
2.50	1					9
160.00	2					10
1.50	1					11
1.50	1					12
7.50	3					13
1.50	1					14
5.00	2					15
2.50	1					16
1.50	1					17
60.00	2					18
2.50	1					19
2.50	1					20
10.00	4					21
12.50	5					22
110.00	2					23
12.50	5					24
10.00	4					25
124.00	2					26
300.00	2					27
3.00	2					28
12.50	5					29
3.00	2					30
15.00	6					31
80.00	1					32
70.00	1					33
65.00	1					34
5.00	2					35
2.50	1					36
1.50	1					37
5.00	2					38
						39
15.00	6					40

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Heartwood	D/U	35.00	4.36	
2	Jackson	D/U	35.00	4.36	
3	Jamison	D/U	35.00	4.36	
4	Jordan	D/U	35.00	4.36	
5	Kellers	D/U	35.00	4.36	
6	Kelly	D/U	35.00	4.36	
7	Keys	D/U	35.00	4.36	
8	Keys	D/U	35.00	4.36	
9	Langhorne	D/U	35.00	4.36	
10	Levitt	D/U	35.00	4.36	
11	Linton	D/U	230.00	35.00	
12	Mearns	D/U	35.00	4.36	
13	Midway	D/U	35.00	4.36	
14	Midway	D/U	35.00	4.36	
15	Midway	D/U	35.00	13.80	
16	Moon	D/U	35.00	4.36	
17	Morgan	D/U	35.00	4.36	
18	Morrisville	D/U	35.00	4.36	
19	Morrisville	D/U	35.00	4.36	
20	Mountain	D/U	35.00	4.36	
21	Nectar	D/U	35.00	4.36	
22	Neshaminy	D/U	138.00	13.80	
23	New Hope	D/U	35.00	4.36	
24	Newtown	D/U	35.00	4.36	
25	Nolan	D/U	35.00	4.36	
26	Palomino	D/U	35.00	4.36	
27	Palomino	D/U	35.00	4.36	
28	Piper	D/U	35.00	4.36	
29	Plumstead	D/U	35.00	4.36	
30	Pools	D/U	35.00	4.36	
31	Richboro	D/U	35.00	4.36	
32	Rickerts	D/U	35.00	4.36	
33	Rodgers	D/U	35.00	13.80	
34	Rushland	D/U	35.00	4.36	
35	Siles	D/U	35.00	4.36	
36	Siles	D/U	35.00	13.80	
37	Solebury	D/U	35.00	4.36	
38	Solebury	D/U	35.00	4.36	
39					
40	Southampton	D/U	35.00	4.36	

SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20.00	8					1
5.00	2					2
2.50	1					3
7.50	3					4
1.50	1					5
1.00	1					6
10.00	4					7
1.50	1					8
5.00	2					9
17.50	7					10
180.00	2					11
2.50	1					12
1.50	1					13
5.00	2					14
5.00	1					15
20.00	8					16
4.50	3					17
4.00	1					18
6.00	1					19
1.50	1					20
2.50	1					21
110.00	2					22
5.00	2					23
12.50	5					24
10.00	4					25
3.00	2					26
7.50	3					27
1.50	1					28
3.00	2					29
5.00	2					30
7.50	3					31
3.00	2					32
10.00	2					33
1.50	1					34
2.50	1					35
5.00	1					36
2.50	1					37
1.50	1					38
						39
5.00	2					40

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Star	D/U	35.00	4.36	
2	Starkey	D/U	35.00	4.36	
3	Stoney	D/U	35.00	4.36	
4	Trevose	D/U	35.00	4.36	
5	Trevose	D/U	35.00	13.80	
6	Tully	D/U	35.00	4.36	
7	Turk	D/U	35.00	4.36	
8	Warminster	D/U	35.00	4.36	
9	Warminster	D/U	230.00	13.80	
10	Warrington	D/U	230.00	35.00	
11	Warrington	D/U	230.00	35.00	
12	Warwick	D/U	35.00	4.36	
13	Westbuck	D/U	35.00	4.36	
14	Westbuck	D/U	35.00	4.36	
15	Woodbourne	D/U	35.00	4.36	
16	Woodbourne	D/U	230.00	35.00	
17	Woodbourne	D/U	230.00	35.00	
18	Worth	D/U	35.00	4.36	
19	Wright	D/U	35.00	4.36	
20	Yardley	D/U	35.00	4.36	
21					
22	Bucks Division (Transmission)				
23	Croydon	T/U	230.00	13.20	
24	Emilie	T/U	230.00	138.00	
25					
26	Chester Division (Distribution)				
27	Cromby	D/U	69.00	35.00	
28	Avondale	D/U	35.00	4.36	
29	Avondale	D/U	35.00	4.36	
30	Bacton	D/U	35.00	4.36	
31	Barnsley	D/U	35.00	4.36	
32	Berwyn	D/U	35.00	4.36	
33	Berwyn	D/U	35.00	4.36	
34	Boot Jack	D/U	35.00	4.36	
35	Boyd	D/U	35.00	4.36	
36	Bradford	D/U	230.00	35.00	
37	Buck	D/U	35.00	4.36	
38	Byers	D/U	35.00	4.36	
39	Caln	D/U	35.00	4.36	
40	Chandler	D/U	35.00	4.36	

SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
1.50	1					1
2.50	1					2
1.50	1					3
10.00	4					4
10.00	2					5
12.50	5					6
2.50	1					7
10.00	4					8
60.00	2					9
80.00	1					10
90.00	1					11
1.50	1					12
1.50	1					13
2.50	1					14
2.50	1					15
80.00	1					16
90.00	1					17
1.50	1					18
2.50	1					19
12.50	5					20
						21
						22
440.00	4					23
300.00	1					24
						25
						26
150.00	2					27
5.00	2					28
1.50	1					29
1.50	1					30
1.50	1					31
5.00	2					32
						33
2.50	1					34
2.50	1					35
180.00	2					36
1.50	1					37
1.50	1					38
2.50	1					39
2.50	1					40

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Charlton	D/U	35.00	4.36	
2	Clay	D/U	230.00	35.00	
3	Coatesville	D/U	35.00	4.36	
4	Cochranville	D/U	230.00	35.00	
5	Cornog	D/U	35.00	4.36	
6	Crest	D/U	35.00	4.36	
7	Devault	D/U	35.00	4.36	
8	Devon	D/U	35.00	4.36	
9	Doe Run	D/U	35.00	4.36	
10	Downingtown	D/U	35.00	4.36	
11	Eagle	D/U	35.00	4.36	
12	Elkview	D/U	35.00	4.36	
13	Ellis	D/U	35.00	4.36	
14	Exton	D/U	35.00	4.36	
15	Faggs	D/U	35.00	4.36	
16	Frazer	D/U	35.00	4.36	
17	Gap	D/U	35.00	4.36	
18	Golf	D/U	35.00	4.36	
19	Goshen	D/U	69.00	35.00	
20	Green Hill	D/U	35.00	4.36	
21	Grove	D/U	35.00	4.36	
22	Hamorton	D/U	35.00	4.36	
23	Hamorton	D/U	35.00	4.36	
24	Harmony	D/U	35.00	4.36	
25	Hayes	D/U	35.00	4.36	
26	Highland	D/U	35.00	4.36	
27	Hollow	D/U	35.00	4.36	
28	Hopewell	D/U	35.00	4.36	
29	Howell	D/U	35.00	4.36	
30	Jennersville	D/U	230.00	35.00	
31	Kaolin	D/U	35.00	4.36	
32	Kelton	D/U	35.00	4.36	
33	Kemble	D/U	35.00	4.36	
34	Kenil	D/U	35.00	4.36	
35	Kennett Square	D/U	35.00	4.36	
36	Kimberton	D/U	35.00	4.36	
37	Kleyona	D/U	35.00	4.36	
38	Landenberg	D/U	35.00	4.36	
39	Lemon	D/U	35.00	4.36	
40	Lemon	D/U	35.00	4.36	

SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
2.50	1					1
90.00	1					2
10.00	4					3
21.00	1					4
5.00	2					5
2.50	1					6
3.00	2					7
5.00	2					8
2.50	1					9
7.50	3					10
2.50	1					11
5.00	2					12
12.50	5					13
1.50	1					14
2.00	2					15
5.00	2					16
2.50	1					17
7.50	3					18
50.00	2					19
2.50	1					20
2.50	1					21
2.50	1					22
1.50	1					23
17.50	7					24
1.50	1					25
2.50	1					26
2.50	1					27
1.00	1					28
2.50	2					29
21.00	1					30
7.50	3					31
2.50	1					32
3.00	2					33
2.50	1					34
15.00	6					35
7.50	3					36
10.00	4					37
2.50	1					38
1.50	1					39
1.00	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [x] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Lenape	D/U	35.00	4.36	
2	Lenape	D/U	230.00	35.00	
3	Leopard	D/U	35.00	4.36	
4	Lime	D/U	35.00	4.36	
5	Linfield	D/U	35.00	4.36	
6	London	D/U	35.00	4.36	
7	London	D/U	35.00	4.36	
8	Ludwig	D/U	35.00	4.36	
9	Lyndell	D/U	35.00	4.36	
10	Malvern	D/U	35.00	4.36	
11	Manor	D/U	35.00	4.36	
12	Marshallton	D/U	35.00	4.36	
13	Marshallton	D/U	35.00	4.36	
14	Matthews	D/U	35.00	4.36	
15	Modena	D/U	35.00	4.36	
16	Newlinville	D/U	230.00	35.00	
17	Newlinville	D/U	35.00	4.36	
18	Norco	D/U	35.00	4.36	
19	North Oxford	D/U	35.00	4.36	
20	North Oxford	D/U	35.00	4.36	
21	Nottingham	D/U	230.00	35.00	
22	Nottingham	D/U	35.00	4.36	
23	Nottingham	D/U	35.00	4.36	
24	Olive	D/U	35.00	4.36	
25	Oxford (w)	D/U	35.00	4.36	
26	Page	D/U	35.00	4.36	
27	Paoli	D/U	35.00	4.36	
28	Parkesburg	D/U	35.00	4.36	
29	Parkesburg	D/U	35.00	4.36	
30	Pennsbury	D/U	35.00	4.36	
31	Phoenixville	D/U	35.00	4.36	
32	Pickering	D/U	35.00	4.36	
33	Pikeland	D/U	35.00	4.36	
34	Planebrook	D/U	35.00	4.36	
35	Planebrook	D/U	230.00	35.00	
36	Planebrook	D/U	230.00	35.00	
37	Planebrook	D/U	230.00	35.00	
38	Planebrook	D/U	230.00	69.00	
39	Pocopson	D/U	35.00	4.36	
40	Porters Mill	D/U	35.00	4.36	

SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
2.50	1					1
90.00	1					2
7.50	3					3
1.50	1					4
2.50	1					5
1.50	1					6
1.00	1					7
1.50	1					8
1.50	1					9
10.00	4					10
4.00	2					11
2.50	1					12
1.50	1					13
2.50	1					14
1.00	1					15
160.00	2					16
2.50	1					17
7.50	3					18
1.50	1					19
2.50	1					20
40.00	1					21
2.50	1					22
1.50	1					23
5.50	3					24
3.00	2					25
2.50	1					26
10.00	4					27
2.50	1					28
1.50	1					29
1.50	1					30
20.00	8					31
5.00	2					32
2.50	1					33
2.50	1					34
300.00	2					35
168.00	1					36
100.00	1					37
						38
2.50	1					39
2.50	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [x] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Porters Mill	D/U	35.00	4.36	
2	Regent	D/U	35.00	4.36	
3	Sadsbury	D/U	35.00	4.36	
4	Sheeder	D/U	35.00	4.36	
5	Ship	D/U	35.00	4.36	
6	Snowden	D/U	35.00	4.36	
7	Spring City	D/U	35.00	4.36	
8	Spring City	D/U	35.00	4.36	
9	Stottsville	D/U	35.00	4.36	
10	Street	D/U	35.00	4.36	
11	Sugartown	D/U	35.00	4.36	
12	Thorndale	D/U	35.00	4.36	
13	Thorndale	D/U	35.00	4.36	
14	Tokena	D/U	35.00	4.36	
15	Tredyffrin	D/U	230.00	13.80	
16	Uwchlan	D/U	35.00	4.36	
17	Uwchlan	D/U	35.00	4.36	
18	Wagontown	D/U	35.00	4.36	
19	Wallace	D/U	35.00	4.36	
20	West Chester	D/U	35.00	4.36	
21	West Grove	D/U	35.00	4.36	
22	Westtown	D/U	35.00	4.36	
23	Wicker	D/U	35.00	4.36	
24	Willis	D/U	35.00	4.36	
25	Willowdale	D/U	35.00	4.36	
26	Willowdale	D/U	35.00	4.36	
27					
28	Chester Division (Transmission)				
29	Cromby	T/**	138.00	69.00	
30	Cromby	T/**	230.00	69.00	
31	Cromby	T/**	69.00	20.00	
32	Cromby	T/**	138.00	20.00	
33	Bradford	T/U	230.00	138.00	
34	Newlinville	T/U	230.00	138.00	
35					
36	Delaware Division (Distribution)				
37	Lamokin Conv.	D/A			
38	Eddystone	D/U	138.00	13.80	
39	Ardmore	D/U	35.00	4.36	
40	Bala	D/U	13.80	4.36	

SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
1.50	1					1
1.50	1					2
2.50	1					3
1.50	1					4
2.50	1					5
2.50	1					6
3.00	1					7
2.50	1					8
1.50	1					9
2.50	1					10
2.50	1					11
5.00	2					12
1.50	1					13
3.00	2					14
60.00	2					15
3.00	2					16
2.50	1					17
2.50	1					18
2.50	1					19
5.00	2					20
3.00	2					21
1.50	1					22
4.00	2					23
1.50	1					24
2.50	1					25
1.50	1					26
						27
						28
170.00	2					29
350.00	2					30
210.00	2					31
240.00	2					32
200.00	1					33
200.00	2					34
						35
						36
45.00	3					37
80.00	2					38
10.00	4					39
20.00	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [x] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Bala	D/U	230.00	13.80	
2	Bethel	D/U	35.00	4.36	
3	Bethel	D/U	35.00	4.36	
4	Bluebell	D/U	69.00	13.80	
5	Booth	D/U	13.80	4.36	
6	Broomall	D/U	35.00	4.36	
7	Broomall	D/U	35.00	13.80	
8	Bryn Mawr	D/U	138.00	35.00	
9	Bryn Mawr	D/U	138.00	35.00	
10	Bryn Mawr	D/U	35.00	4.36	
11	Bryn Mawr	D/U	138.00	13.80	
12	Castle	D/U	35.00	4.36	
13	Chadds	D/U	35.00	4.36	
14	Chester	D/U	35.00	13.80	
15	Chichester	D/U	69.00	13.80	
16	Chichester	D/U	230.00	13.60	
17	Clifton	D/U	35.00	4.36	
18	Clifton	D/U	35.00	4.36	
19	Colwyn	D/U	35.00	4.36	
20	Colwyn	D/U	35.00	13.80	
21	Concord	D/U	230.00	35.00	
22	Concord	D/U	35.00	4.36	
23	Creek	D/U	35.00	4.36	
24	Crum Lynne	D/U	35.00	13.80	
25	Diltown	D/U	35.00	4.36	
26	Dutton	D/U	35.00	4.36	
27	Edgemont	D/U	35.00	4.36	
28	Edgemont	D/U	35.00	13.80	
29	Faulk	D/U	35.00	4.36	
30	Foulk	D/U	230.00	13.80	
31	Front	D/U	13.80	4.36	
32	Garrett	D/U	35.00	4.36	
33	Gladwyne	D/U	35.00	4.36	
34	Gladwyne	D/U	35.00	13.80	
35	Grady	D/U	35.00	4.36	
36	Hagys	D/U	13.80	4.36	
37	Hagys	D/U	13.80	4.36	
38	Harvey	D/U	35.00	4.36	
39	Hunt	D/U	35.00	13.80	
40	Keystone	D/U	35.00	4.36	

SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor,. date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
110.00	2					1
3.00	2					2
2.50	1					3
168.00	2					4
7.50	3					5
7.50	3					6
5.00	1					7
80.00	1					8
70.00	1					9
10.00	4					10
110.00	2					11
2.50	1					12
2.50	1					13
80.00	2					14
80.00	2					15
110.00	2					16
5.00	2					17
4.50	3					18
3.00	2					19
10.00	2					20
160.00	2					21
5.00	2					22
2.50	1					23
5.00	1					24
5.00	2					25
10.00	4					26
7.50	3					27
5.00	1					28
2.50	1					29
60.00	2					30
5.00	2					31
12.50	5					32
1.50	1					33
5.00	1					34
2.50	1					35
5.00	2					36
2.25	1					37
5.00	2					38
5.00	1					39
13.33	1					40

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Keystone	D/U	35.00	4.36	
2	Knowlton	D/U	35.00	4.36	
3	Lamokin	D/U	13.80	4.36	
4	Larchmont	D/U	35.00	4.36	
5	Lester	D/U	13.80	4.36	
6	Llanerch	D/U	35.00	4.36	
7	Llanerch	D/U	138.00	35.00	
8	Llanerch	D/U	138.00	35.00	
9	Llanerch	D/U	138.00	13.80	
10	Llanerch	D/U	138.00	13.60	
11	Macdade	D/U	230.00	13.80	
12	Macdade	D/U	230.00	13.80	
13	Marcus Hook	D/U	69.00	13.80	
14	Marple	D/U	35.00	4.36	
15	Marple	D/U	35.00	13.80	
16	Media	D/U	35.00	4.36	
17	Media	D/U	35.00	13.80	
18	Middletown	D/U	230.00	13.80	
19	Middletown	D/U	230.00	35.00	
20	Middletown	D/U	230.00	69.00	
21	Monroe	D/U	35.00	4.36	
22	Morton	D/U	230.00	13.80	
23	Morton	D/U	35.00	4.36	
24	Morton	D/U	230.00	13.80	
25	Morton	D/U	35.00	4.36	
26	Oakmont	D/U	35.00	4.36	
27	Prospect	D/U	35.00	4.36	
28	Riddle	D/U	35.00	4.36	
29	Saville	D/U	138.00	13.80	
30	Scott	D/U	35.00	4.36	
31	Secane	D/U	35.00	13.80	
32	Sharon Hill	D/U	69.00	35.00	
33	Sharon Hill	D/U	35.00	4.36	
34	Smithbridge	D/U	35.00	4.36	
35	Springfield	D/U	35.00	4.36	
36	Springfield	D/U	35.00	4.36	
37	Sproul	D/U	35.00	4.36	
38	Tanguy	D/U	35.00	4.36	
39	Thomson	D/U	35.00	4.36	
40	Thomson	D/U	35.00	13.80	

SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
10.00	1					1
10.00	4					2
4.50	2					3
10.00	4					4
7.50	3					5
11.24	2					6
70.00	1					7
80.00	1					8
165.00	3					9
55.00	1					10
62.00	1					11
55.00	1					12
40.00	2					13
15.00	6					14
5.00	1					15
5.00	2					16
5.00	1					17
124.00	2					18
80.00	1					19
100.00	1					20
15.00	6					21
124.00	2					22
7.50	3					23
						24
						25
12.50	5					26
7.50	3					27
2.50	1					28
110.00	2					29
3.00	2					30
17.50	6					31
40.00	1					32
2.50	1					33
2.50	1					34
10.00	4					35
3.00	2					36
10.00	4					37
1.50	1					38
10.00	4					39
5.00	1					40

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Upper Darby	D/U	35.00	4.36	
2	Upper Darby	D/U	35.00	4.36	
3	Upper Darby	D/U	69.00	35.00	
4	Upper Darby	D/U	69.00	13.80	
5	Wawa	D/U	35.00	4.36	
6	Wayne	D/U	35.00	13.80	
7	Westgate	D/U	35.00	4.36	
8	Woodlyn	D/U	69.00	35.00	
9	Woodlyn	D/U	35.00	13.80	
10	Wynnewood	D/U	35.00	4.36	
11	Yeadon	D/U	35.00	13.80	
12					
13	Delaware Division (Transmission)				
14	Eddystone	T/**	230.00	23.40	
15	Eddystone	T/**	138.00	69.00	
16	Eddystone	T/**	230.00	138.00	
17	Eddystone	T/**	138.00	20.00	
18	Eddystone	T/**	138.00	13.80	
19	Eddystone	T/**	230.00	13.80	
20	Chester	T/U	69.00	13.80	
21	Chester	T/U	69.00	13.80	
22	Chichester	T/U	138.00	69.00	
23	Chichester	T/U	230.00	138.00	
24	Llanerch	T/U	138.00	69.00	
25	Woodlyn	T/U	138.00	69.00	
26					
27	MONTGOMERGY DIVISION (DISTRIBUTION)				
28	Abington	D/U	35.00	4.36	
29	Acorn	D/U	35.00	4.36	
30	Airy	D/U	35.00	4.36	
31	Airy	D/U	35.00	13.80	
32	Allen	D/U	35.00	4.36	
33	Ambler	D/U	35.00	4.36	
34	Audubon	D/U	35.00	4.36	
35	Barbadoes	D/U	230.00	35.00	
36	Barbadoes	D/U	230.00	35.00	
37	Beidler	D/U	35.00	13.80	
38	Belmont	D/U	35.00	4.36	
39	Berks	D/U	35.00	4.36	
40	Bethayres	D/U	35.00	4.36	

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
12.50	1					1
26.66	2					2
40.00	1					3
110.00	2					4
2.50	1					5
80.00	2					6
2.50	1					7
160.00	2					8
5.00	1					9
18.00	3					10
5.00	1					11
						12
						13
880.00	2					14
100.00	1					15
280.00	1					16
800.00	4					17
40.00	2					18
37.50	1					19
40.00	2					20
60.00	1					21
200.00	2					22
300.00	1					23
100.00	1					24
200.00	2					25
						26
						27
15.00	6					28
2.50	1					29
7.50	3					30
5.00	1					31
5.00	2					32
7.50	3					33
12.50	5					34
165.00	1					35
90.00	1					36
5.00	1					37
12.50	5					38
2.50	1					39
5.00	2					40

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Bethayres	D/U	35.00	13.80	
2	Bridgeport	D/U	35.00	4.36	
3	Cabot	D/U	35.00	4.36	
4	Cabot	D/U	35.00	13.80	
5	Carmel	D/U	35.00	4.36	
6	Clemens	D/U	35.00	4.36	
7	Collegeville	D/U	35.00	4.36	
8	Colmar	D/U	35.00	4.36	
9	County Line	D/U	35.00	4.36	
10	Creamery	D/U	35.00	4.36	
11	Crusher	D/U	35.00	4.36	
12	Davisville	D/U	35.00	4.36	
13	Elkins Park	D/U	35.00	4.36	
14	Evans	D/U	35.00	4.36	
15	Fair	D/U	35.00	4.36	
16	Flint	D/U	230.00	13.80	
17	Forrest	D/U	35.00	4.36	
18	Hanover	D/U	35.00	4.36	
19	Hatboro	D/U	35.00	4.36	
20	Hatboro	D/U	35.00	13.80	
21	Heaton	D/U	138.00	35.00	
22	Heaton	D/U	138.00	35.00	
23	Heaton	D/U	138.00	13.80	
24	Heaton	D/U	230.00	13.80	
25	Heaton	D/U	230.00	13.80	
26	Henderson	D/U	35.00	4.36	
27	Holiday	D/U	35.00	4.36	
28	Horsham	D/U	35.00	4.36	
29	Jarrett	D/U	230.00	13.80	
30	Jeffersonville	D/U	35.00	4.36	
31	Jenkintown	D/U	230.00	35.00	
32	Jenkintown	D/U	230.00	13.80	
33	Keith	D/U	35.00	4.36	
34	King	D/U	35.00	4.36	
35	Kulps	D/U	35.00	4.36	
36	Kulps	D/U	35.00	4.36	
37	Lane	D/U	35.00	4.36	
38	Lantern	D/U	35.00	4.36	
39	Lederach	D/U	35.00	4.36	
40	Lewis	D/U	35.00	4.36	

SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
5.00	1					1
10.00	4					2
15.00	6					3
10.00	2					4
10.00	4					5
2.50	1					6
5.00	2					7
5.00	2					8
17.50	7					9
2.50	1					10
2.50	1					11
17.50	7					12
9.37	1					13
5.00	2					14
10.00	4					15
124.00	2					16
12.50	5					17
10.00	4					18
15.00	2					19
5.00	1					20
80.00	1					21
70.00	1					22
220.00	4					23
200.00	1					24
						25
5.00	2					26
2.50	1					27
7.50	3					28
124.00	2					29
12.50	5					30
80.00	1					31
165.00	3					32
2.50	1					33
10.00	4					34
5.00	2					35
3.00	2					36
5.00	2					37
2.50	1					38
6.00	4					39
2.50	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PECO Energy Company	(1) [x] An Original (2) [ ] A Resubmission	12/31/96	Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Lewis	D/U	35.00	4.36	
2	Lincoln	D/U	35.00	4.36	
3	Mainland	D/U	35.00	4.36	
4	Maple Hill	D/U	35.00	4.36	
5	Markley	D/U	35.00	4.36	
6	Markley	D/U	35.00	13.80	
7	Mont Clare	D/U	35.00	4.36	
8	Montgomery	D/U	35.00	4.36	
9	Morewood	D/U	35.00	4.36	
10	Moser	D/U	69.00	35.00	
11	Moser	D/U	35.00	13.80	
12	Moser	D/U	35.00	4.36	
13	Moser	D/U	35.00	4.36	
14	Norristown	D/U	35.00	4.36	
15	North Wales	D/U	230.00	35.00	
16	North Wales	D/U	230.00	35.00	
17	North Wales	D/U	35.00	4.36	
18	Oaks	D/U	35.00	4.36	
19	Penllyn	D/U	35.00	4.36	
20	Perkiomen	D/U	138.00	35.00	
21	Perkiomen	D/U	230.00	35.00	
22	Plymouth Meeting	D/U	138.00	35.00	
23	Plymouth Meeting	D/U	230.00	13.60	
24	Plymouth Meeting	D/U	230.00	13.80	
25	Plymouth Meeting	D/U	230.00	13.80	
26	Point	D/U	35.00	4.36	
27	Poplar	D/U	35.00	4.36	
28	Rahns	D/U	35.00	4.36	
29	Royersford	D/U	35.00	4.36	
30	Royersford	D/U	35.00	4.36	
31	Salford	D/U	35.00	4.36	
32	Sanatoga	D/U	35.00	4.36	
33	Schwenksville	D/U	35.00	4.36	
34	Stowe	D/U	35.00	4.36	
35	Stump	D/U	35.00	4.36	
36	Trappe	D/U	35.00	4.36	
37	Trooper	D/U	35.00	4.36	
38	Upper Marion	D/U	230.00	35.00	
39	Upper Marion	D/U	230.00	13.60	
40	Vaughn	D/U	35.00	4.36	

SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
1.50	1					1
9.00	6					2
2.50	1					3
2.50	1					4
7.50	3					5
5.00	1					6
2.50	1					7
2.50	1					8
2.50	1					9
120.00	3					10
65.00	1					11
1.50	1					12
5.00	2					13
26.66	2					14
80.00	1					15
330.00	2					16
15.00	6					17
2.50	1					18
10.00	4					19
140.00	2					20
168.00	1					21
80.00	1					22
55.00	1					23
62.00	1					24
55.00	1					25
5.00	2					26
12.50	5					27
2.50	1					28
5.00	2					29
4.50	3					30
1.50	1					31
1.50	1					32
5.00	2					33
7.50	3					34
5.00	2					35
5.00	2					36
7.50	3					37
330.00	2					38
124.00	2					39
2.50	1					40

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Washington SQ.	D/U	35.00	4.36	
2	Welsh	D/U	35.00	4.36	
3	Wentz	D/U	35.00	4.36	
4	Westover	D/U	35.00	4.36	
5	Whitemarsh	D/U	230.00	13.80	
6	Whitemarsh	D/U	69.00	35.00	
7	Woxall	D/U	35.00	4.36	
8	Wyncote	D/U	35.00	4.36	
9	Montgomery Division (Transmission)				
10	Limerick	T/**	35.00	13.80	
11	Limerick	T/**	22.00	220.00	
12	Limerick	T/**	230.00	13.80	
13	Limerick	T/**	500.00	20.90	
14	Limerick	T/**	500.00	230.00	
15	Plymouth Meeting	T/U	230.00	138.00	
16	Whitemarsh	T/U	230.00	69.00	
17	Whitpain	T/U	500.00	230.00	
18					
19	Philadelphia Division (North)				
20	Richmond Conv.	D/A			
21	Somerset Conv.	D/A			
22	Richmond	D/U	230.00	13.80	
23	Allegheny	D/U	13.80	2.52	
24	Ashton	D/U	13.80	4.36	
25	Beach	D/U	13.80	2.52	
26	Benner	D/U	13.80	4.36	
27	Blue Grass	D/U	138.00	13.60	
28	Blue Grass	D/U	138.00	13.80	
29	Burholme	D/U	69.00	13.80	
30	Burholme	D/U	13.80	4.36	
31	Bustleton	D/U	13.80	4.36	
32	Byberry	D/U	138.00	35.00	
33	Byberry	D/U	138.00	13.60	
34	Byberry	D/U	138.00	13.60	
35	Carlisle	D/U	13.80	2.52	
36	Cedarbrook	D/U	69.00	13.80	
37	Cedarbrook	D/U	13.80	4.36	
38	Chestnut Hill	D/U	13.80	4.36	
39	Columbia	D/U	13.80	2.52	
40	Crescentville	D/U	138.00	13.80	

Name of Respondent PECO Energy Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
7.50	5					1
5.00	2					2
1.50	1					3
2.50	1					4
110.00	2					5
40.00	1					6
1.50	1					7
20.00	2					8
						9
3.75	1					10
1,161.00	3					11
55.00	1					12
1,164.00	3					13
840.00	2					14
200.00	1					15
105.00	1					16
1,950.00	3					17
						18
						19
60.00	2					20
18.00	3					21
165.00	3					22
21.00	3					23
7.50	3					24
3.00	2					25
30.00	3					26
110.00	2					27
120.00	3					28
120.00	6					29
37.50	3					30
5.00	2					31
70.00	1					32
165.00	3					33
124.00	2					34
14.00	2					35
160.00	4					36
25.00	2					37
30.00	3					38
4.50	3					39
160.00	4					40

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Crescentville	D/U	138.00	13.60	
2	Crescentville	D/U	138.00	13.60	
3	Fox Chase	D/U	138.00	13.80	
4	Gaul	D/U	13.80	2.52	
5	Germantown	D/U	13.80	4.36	
6	Holmesburg	D/U	69.00	13.80	
7	Holmesburg	D/U	138.00	13.80	
8	Holmesburg	D/U	13.80	4.36	
9	Hunting Park	D/U	13.80	4.36	
10	Hunting Park	D/U	69.00	13.80	
11	Indiana	D/U	13.80	2.52	
12	Kerbaugh	D/U	13.80	4.36	
13	Logan	D/U	13.80	4.36	
14	Longshore	D/U	13.80	4.36	
15	Loretto	D/U	13.80	4.36	
16	Luzerne	D/U	13.80	4.36	
17	Main	D/U	13.80	4.36	
18	Manayunk	D/U	13.80	4.36	
19	Morris	D/U	13.80	4.36	
20	Nice	D/U	13.80	2.52	
21	North Phila.	D/U	69.00	13.80	
22	Orthodox	D/U	13.80	2.52	
23	Oxford	D/U	13.80	2.52	
24	Pencoyd	D/U	69.00	13.80	
25	Pencoyd	D/U	69.00	13.80	
26	Pencoyd	D/U	13.80	4.36	
27	Pike	D/U	13.80	4.36	
28	Pulaski	D/U	230.00	13.60	
29	Richmond	D/U	230.00	13.80	
30	Rockwell	D/U	13.80	4.36	
31	Roxborough	D/U	69.00	13.80	
32	Salmon	D/U	13.80	2.52	
33	Sedgley	D/U	13.80	2.52	
34	Somerset	D/U	13.80	2.52	
35	Spencer	D/U	13.80	4.36	
36	State	D/U	13.80	4.36	
37	Susquehanna (P)	D/U	13.80	2.52	
38	Tabor	D/U	230.00	13.80	
39	Tackawanna	D/U	13.80	2.52	
40	Tacony	D/U	69.00	13.80	

SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
55.00	1					1
55.00	1					2
110.00	2					3
6.00	4					4
30.00	3					5
40.00	2					6
110.00	2					7
15.00	6					8
33.75	3					9
40.00	4					10
21.00	3					11
20.00	2					12
30.00	3					13
37.50	3					14
20.00	2					15
15.00	6					16
2.25	1					17
2.50	1					18
30.00	3					19
3.00	2					20
160.00	4					21
1.50	1					22
30.00	4					23
40.00	2					24
80.00	2					25
5.00	2					26
20.00	2					27
110.00	2					28
165.00	3					29
7.50	3					30
80.00	2					31
21.00	14					32
1.50	1					33
12.00	8					34
30.00	3					35
10.00	4					36
30.00	4					37
110.00	2					38
14.00	2					39
80.00	2					40

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Tacony	D/U	13.80	4.36	
2	Tulip	D/U	13.80	2.52	
3	Venango	D/U	13.80	2.52	
4	Waneeta	D/U	230.00	13.60	
5	West Oak Lane	D/U	13.80	4.36	
6	Westmoreland	D/U	69.00	13.80	
7	Westmoreland	D/U	69.00	13.80	
8	Whitaker	D/U	13.80	4.36	
9	Wigard	D/U	13.80	4.36	
10	Windrim	D/U	13.80	4.36	
11	Wissinoming	D/U	13.80	2.52	
12	Wister	D/U	13.80	4.36	
13	York	D/U	13.80	2.52	
14	Philadelphia Division (North) Transmission				
15	Delaware	T/**	69.00	13.80	
16	Delaware	T/**	138.00	13.80	
17	Richmond	T/**	69.00	13.80	
18	Richmond	T/**	69.00	13.80	
19	Richmond	T/**	220.00	13.20	
20	Richmond	T/**	220.00	13.20	
21	Byberry	T/U	138.00	69.00	
22	Byberry	T/U	230.00	138.00	
23	Holmesburg	T/U	230.00	138.00	
24	Holmesburg	T/U	138.00	69.00	
25	Master	T/U	138.00	69.00	
26	Master	T/U	230.00	138.00	
27	Master	T/U	138.00	69.00	
28	North Phila.	T/U	230.00	69.00	
29	Roxborough	T/U	230.00	69.00	
30	Waneeta	T/U	230.00	138.00	
31					
32	Philadelphia Division (South) Distribution				
33	Angora	D/U	69.00	13.80	
34	Angora	D/U	13.80	4.36	
35	Bucknell	D/U	13.80	4.36	
36	Callowhill	D/U	138.00	13.80	
37	Callowhill	D/U	138.00	13.80	
38	Callowhill	D/U	138.00	13.80	
39	Callowhill	D/U	13.80	2.52	
40	Callowhill	D/U	13.80	2.52	

SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
10.00	4					1
1.50	1					2
1.50	1					3
110.00	2					4
37.50	3					5
40.00	1					6
150.00	2					7
2.50	1					8
10.00	4					9
5.00	2					10
3.00	2					11
2.50	1					12
21.00	3					13
						14
110.00	1					15
110.00	1					16
75.00	1					17
100.00	1					18
60.00	1					19
120.00	1					20
100.00	2					21
300.00	1					22
200.00	1					23
100.00	1					24
200.00	2					25
300.00	1					26
100.00	2					27
200.00	2					28
110.00	1					29
300.00	1					30
						31
						32
80.00	2					33
30.00	3					34
2.50	1					35
160.00	4					36
45.00	1					37
165.00	3					38
12.50	1					39
10.00	1					40

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Elmwood	D/U	230.00	13.80	
2	Ferry	D/U	13.80	4.36	
3	Grays Ferry	D/U	230.00	13.80	
4	Grays Ferry	D/U	230.00	13.80	
5	Island Road	D/U	69.00	13.80	
6	Island Road	D/U	69.00	13.80	
7	Island Road	D/U	230.00	13.80	
8	Island Road	D/U	13.80	4.36	
9	Johnston	D/U	13.80	4.36	
10	Laurel	D/U	13.80	2.52	
11	Lawrence	D/U	13.80	4.36	
12	Lombard	D/U	69.00	13.60	
13	Lombard	D/U	69.00	13.80	
14	Lombard	D/U	13.80	2.52	
15	Ludlow	D/U	13.80	2.52	
16	Mall	D/U	13.80	2.52	
17	Oregon	D/U	13.80	4.36	
18	Overbrook	D/U	35.00	4.36	
19	Overbrook	D/U	35.00	13.80	
20	Packer	D/U	69.00	13.80	
21	Parrish	D/U	230.00	13.80	
22	Parrish	D/U	230.00	13.60	
23	Passyunk	D/U	69.00	13.80	
24	Passyunk	D/U	69.00	13.60	
25	Penn	D/U	69.00	13.80	
26	Pentridge	D/U	13.80	4.36	
27	Pentridge	D/U	13.80	4.36	
28	Powelton	D/U	13.80	4.36	
29	Race	D/U	13.80	4.36	
30	Sherwood	D/U	35.00	4.36	
31	Snyder	D/U	13.80	4.36	
32	Spring Garden	D/U	13.80	2.52	
33	Spruce	D/U	13.80	2.52	
34	Taylor	D/U	13.80	2.52	
35	University	D/U	69.00	13.60	
36	Waverly	D/U	13.80	2.52	
37	Philadelphia Division (South) Transmission				
38	Schuylkill	T/**	69.00	13.80	
39	Schuylkill	T/**	69.00	13.80	
40	Schuylkill	T/**	230.00	69.00	

SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others,jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
110.00	2					1
5.00	2					2
110.00	2					3
62.00	1					4
80.00	2					5
40.00	2					6
124.00	2					7
5.00	2					8
15.00	6					9
12.00	8					10
10.00	4					11
40.00	1					12
200.00	5					13
19.34	2					14
37.50	5					15
30.00	4					16
30.00	3					17
22.50	3					18
5.00	1					19
80.00	2					20
110.00	2					21
55.00	1					22
200.00	5					23
40.00	1					24
160.00	4					25
15.00	6					26
1.50	1					27
45.00	4					28
45.00	4					29
20.00	2					30
14.50	6					31
21.00	3					32
30.00	4					33
3.00	2					34
80.00	2					35
30.00	4					36
						37
150.00	2					38
120.00	2					39
600.00	2					40

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.

2. Substations which serve only one industrial or street railway customer should not be listed below.

3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.

4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Schuylkill	T/**	69.00	13.80	
2	Island Road	T/U	230.00	69.00	
3	Passyunk	T/U	230.00	69.00	
4	Southwark	T/U	69.00	13.80	
5	Southwark	T/U	69.00	13.80	
6					
7	York County Division (Distribution)				
8	Delta	D/U	35.00	4.36	
9	Fin	D/U	35.00	4.36	
10	Slate	D/U	35.00	4.36	
11	Sunnyburn	D/U	35.00	4.36	
12					
13	York County Division (Transmission)				
14	Muddy Run	T/**	230.00	13.80	
15	Peach Bottom	T/**	500.00	230.00	
16	Peach Bottom	T/**	500.00	20.90	
17	Peach Bottom	T/**	230.00	13.80	
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (i),(j),and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased *from others, jointly owned with others, or operated otherwise* than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between *the parties, and state amounts and accounts affected in respondent's* books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
220.00	2					1
150.00	1					2
136.00	1					3
300.00	3					4
80.00	2					5
						6
						7
2.50	2					8
2.50	2					9
1.00	1					10
2.50	2					11
						12
						13
1,000.00	4					14
1,120.00	1					15
2,340.00	2					16
30.00	1					17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

< Page 426 Line 1 Column B >

LEGENDS

COLUMN (b)

D = Distribution

T = Transmission

U = Unattended

A = Attended

** = Attended from adjacent generating station.

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ELECTRIC DISTRIBUTION METERS AND LINE TRANSFORMERS

1. Report below the information called for concerning distribution watt-hour meters and line transformers.

2. Include watt-hour demand distribution meters, but not external demand meters.

3. Show in a footnote the number of distribution watt-hour meters or line transformers held by the respondent under lease from others, jointly owned with others, or held otherwise than by reason of sole ownership by the respondent. If 500 or more meters or line transformers are held under a lease, give name of lessor, date and period of lease, and annual rent. If 500 or more meters or line transformers are held other than by reason of sole ownership or lease, give name of co-owner or other parties, explain basis of accounting for expenses between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Item (a)	Number of Watt-Hour Meters (b)	LINE TRANSFORMERS	
			Number (c)	Total Capacity (In MVa) (d)
1	Number at Beginning of Year	1,753,573	175,679	12,467
2	Additions During Year			
3	Purchases	52,321	3,732	325
4	Associated with Utility Plant Acquired			
5	TOTAL Additions (Enter Total of lines 3 and 4)	52,321	3,732	325
6	Reductions During Year			
7	Retirements	18,052	370	26
8	Associated with Utility Plant Sold			
9	TOTAL Reductions (Enter Total of lines 7 and 8)	18,052	370	26
10	Number at End of Year (Lines 1+5-9)	1,787,842	179,041	12,766
11	In Stock	16,787	935	
12	Locked Meters on Customers' Premises	35,000		
13	Inactive Transformers on System		33	1
14	In Customers' Use	1,735,887	177,703	12,731
15	In Company's Use	168	370	34
16	TOTAL End of Year (Enter Total of lines 11 to 15. This line should equal line 10.)	1,787,842	179,041	12,766

ENVIRONMENTAL PROTECTION FACILITIES

1. For purposes of this response, environmental protection facilities shall be defined as any building, structure, equipment, facility, or improvement designed and constructed solely for control, reduction, prevention or abatement of discharges or releases into the environment of gaseous, liquid, or solid substances, heat, noise or for the control, reduction, prevention, or abatement of any other adverse impact of an activity on the environment.

2. Report the differences in cost of facilities installed for environmental considerations over the cost of alternative facilities which would otherwise be used without environmental considerations. Use the best engineering design achievable without environmental restrictions as the basis for determining costs without environmental considerations. It is not intended that special design studies be made for purposes of this response. Base the response on the best engineering judgement where direct comparisons are not available.

Include in these differences in costs the costs or estimated costs of environmental protection facilities in service, constructed or modified in connection with the production, transmission, and distribution of electrical energy and shall be reported herein for all such environmental facilities placed in service on or after January 1, 1969, so long as it is readily determinable that such facilities were constructed or modified for environmental rather than operational purposes. Also report similar expenditures for environmental plant included in construction work in progress. Estimate the cost of facilities when the original cost is not available or facilities are jointly owned with another utility, provided the respondent explains the basis of such estimations.

Examples of these costs would include a portion of the costs of tall smokestacks, underground lines, and landscaped substations. Explain such costs in a footnote.

3. In the cost of facilities reported on this page, include an estimated portion of the cost of plant that is or will be used to provide power to operate associated environmental protection facilities. These costs may be estimations on a percentage of plant basis. Explain such estimations in a footnote.

4. Report all costs under the major classifications provided below and include, as a minimum, the items listed hereunder:

A. Air pollution control facilities:
   (1) Scrubbers, precipitators, tall smokestacks, etc.
   (2) Changes necessary to accommodate use of environmentally clean fuels such as low ash or low sulfur fuels including storage and handling equipment
   (3) Monitoring equipment
   (4) Other.

B. Water pollution control facilities:
   (1) Cooling towers, ponds, piping, pumps, etc.
   (2) Waste water treatment equipment
   (3) Sanitary waste disposal equipment
   (4) Oil interceptors
   (5) Sediment control facilities
   (6) Monitoring equipment
   (7) Other.

C. Solid waste disposal costs:
   (1) Ash handling and disposal equipment
   (2) Land
   (3) Settling ponds
   (4) Other.

D. Noise abatement equipment:
   (1) Structures
   (2) Mufflers
   (3) Sound proofing equipment
   (4) Monitoring equipment
   (5) Other.

E. Esthetic costs:
   (1) Architectural costs
   (2) Towers
   (3) Underground lines
   (4) Landscaping
   (5) Other.

F. Additional plant capacity necessary due to restricted output from existing facilities, or addition of pollution control facilities.

G. Miscellaneous:
   (1) Preparation of environmental reports
   (2) Fish and wildlife plants included in Accounts 330, 331, 332, and 335.
   (3) Parks and related facilities
   (4) Other.

5. In those instances when costs are composites of both actual supportable costs and estimates of costs, specify in column (f) the actual costs that are included in column (e).

6. Report construction work in progress relating to environmental facilities at line 9.

Line No.	Classification of Cost (a)	CHANGES DURING YEAR Additions (b)	Retirements (c)	Adjustments (d)	Balance at End of Year (e)	Actual Cost (f)
1	Air Pollution Control Facilities	$7,865,235	$3,186,885		$1,944,952,139	$1,944,952,139
2	Water Pollution Control Facilities	3,445,895		(30,864)	476,774,964	476,774,964
3	Solid Waste Disposal Costs				61,665,393	61,665,393
4	Noise Abatement Equipment				3,907,374	3,907,374
5	Esthetic Costs				10,110,038	10,110,038
6	Additional Plant Capacity			(552,162)		
7	Miscellaneous (Identify significant)				431,537	431,537
8	TOTAL (Total of lines 1 thru 7)	$11,311,130	$3,186,885	($583,026)	$2,497,841,445	$2,497,841,445
9	Construction Work in Progress	12,568,308		(5,196,969)	36,830,960	36,830,960

Name of Respondent PECO Energy Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/96	Year of Report Dec. 31, 1996

ENVIRONMENTAL PROTECTION EXPENSES

1. Show below expenses incurred in connection with the use of environmental protection facilities, the cost of which are reported on page 430. Where it is necessary that allocations and/or estimates of costs be made, state the basis or method used.

2. Include below the costs incurred due to the operation of environmental protection equipment, facilities, and programs.

3. Report expenses under the subheadings listed below.

4. Under item 6 report the difference in cost between environmentally clean fuels and the alternative fuels that would otherwise be used and are available for use.

5. Under item 7 include the cost of replacement power, purchased or generated, to compensate for the deficiency in output from existing plants due to the addition of pollution control equipment, use of alternate environmentally preferable fuels or environmental regulations of governmental bodies. Base the price of replacement power purchased on the average system price of purchased power if the actual cost of such replacement power is not known. Price internally generated replacement power at the system average cost of power generated if the actual cost of specific replacement generation is not known.

6. Under item 8 include ad valorem and other taxes assessed directly on or directly relatable to environmental facilities. Also include under item 8 licensing and similar fees on such facilities.

7. In those instances where expenses are composed of both actual supportable data and estimates of costs, specify in column (c) the actual expenses that are included in column (b).

Line No.	Classification of Expenses (a)	Amount (b)	Actual Expenses (c)
1	Depreciation	$115,233,000	$115,233,000
2	Labor, Maintenance, Materials, and Supplies Cost Related to Env. Facilities and Programs	23,758,691	23,758,691
3	Fuel Related Costs		
4	Operation of Facilities	7,923,833	7,923,833
5	Fly Ash and Sulfur Sludge Removal	4,075,592	4,075,592
6	Difference in Cost of Environmentally Clean Fuels	8,533,221	8,533,221
7	Replacement Power Costs	4,606,161	4,606,161
8	Taxes and Fees	14,538,107	14,538,107
9	Administrative and General	1,288,250	1,288,250
10	Other (Identify significant)	471,850	471,850
11	TOTAL	$180,428,705	$180,428,705

INDEX

Schedule	Page No.
Accrued and prepaid taxes	262-263
Accumulated Deferred Income Taxes	234
Accumulated provisions for depreciation of	272-277
common utility plant	356
utility plant	219
utility plant (summary)	200-201
Advances	
from associated companies	256-257
Allowances	228-229
Amortization	
miscellaneous	340
of nuclear fuel	202-203
Appropriations of Retained Earnings	118-119
Associated Companies	
advances from	256-257
corporations controlled by respondent	103
control over respondent	102
interest on debt to	256-257
Attestation	1
Balance sheet	
comparative	110-113
notes to	122-123
Bonds	256-257
Capital Stock	251
discount	254
expense	254
installments received	252
premiums	252
reacquired	251
subscribed	252
Cash flows, statement of	120-121
Changes	
important during year	108-109
Construction	
overheads, electric	217
overhead procedures, general description of	218
work in progress - common utility plant	356
work in progress - electric	216
work in progress - other utility departments	200-201
Control	
corporations controlled by respondent	103
over respondent	102
security holders and voting powers	106-107
Corporation	
controlled by	103
incorporated	101
CPA, background information on	101
CPA Certification, this report form	i-ii

Schedule	Page No.
Deferred	
credits, other	269
debits, miscellaneous	233
income taxes accumulated - accelerated amortization property	272-273
income taxes accumulated - other property	274-275
income taxes accumulated - other	276-277
income taxes accumulated - pollution control facilities	234
Definitions, this report form	iii
Depreciation and amortization	
of common utility plant	356
of electric plant	219
	336-337
Directors	105
Discount on capital stock	254
Discount - premium on long-term debt	256-257
Distribution of salaries and wages	354-355
Dividend appropriations	118-119
Earnings, Retained	118-119
Electric energy account	401
Environmental protection	
expenses	431
facilities	430
Expenses	
electric operation and maintenance	320-323
electric operation and maintenance, summary	323
unamortized debt	256
Extraordinary property losses	230
Filing requirements, this report form	i-ii
General description of construction overhead procedure	218
General information	101
Instructions for filing the FERC Form 1	i-iv
Generating plant statistics	
hydroelectric (large)	406-407
pumped storage (large)	408-409
small plants	410-411
steam-electric (large)	402-403
Hydro-electric generating plant statistics	406-407
Identification	1
Important changes during year	108-109
Income	
statement of, by departments	114-117
statement of, for the year (see also revenues)	114-117
deductions, interest on debt to associated companies	340
deductions, miscellaneous amortization	340
deductions, other income deduction	340
deductions, other interest charges	340
Incorporation information	101
Installments received on capital stock	252

Schedule	Page No.
Interest	
charges, on debt to associated companies	340
charges, other	340
charges, paid on long-term debt, advances, etc.	256-257
Investments	
nonutility property	221
subsidiary companies	224-225
Investment tax credits, accumulated deferred	266-267
Law, excerpts applicable to this report form	iv
List of schedules, this report form	2-4
Long-term debt	256-257
Losses - Extraordinary property	230
Materials and supplies	227
Meters and line transformers	429
Miscellaneous general expenses	335
Notes	
to balance sheet	122-123
to statement of changes in financial position	122-123
to statement of income	122-123
to statement of retained earnings	122-123
Nonutility property	221
Nuclear fuel materials	202-203
Nuclear generating plant, statistics	402-403
Number of Electric Department Employees	323
Officers and officers' salaries	104
Operating	
expenses - electric	320-323
expenses - electric (summary)	323
Other	
paid-in capital	253
donations received from stockholders	253
gains on resale or cancellation of reacquired capital stock	253
miscellaneous paid-in capital	253
reduction in par or stated value of capital stock	253
regulatory assets	232
regulatory liabilities	278
Overhead, construction - electric	217
Peaks, monthly, and output	401
Plant, Common utility	
accumulated provision for depreciation	356
acquisition adjustments	356
allocated to utility departments	356
completed construction not classified	356
construction work in progress	356
expenses	356
held for future use	356
in service	356
leased to others	356
Plant data	217-218 336-337 401-429

Schedule	Page No.
Plant - electric	
accumulated provision for depreciation	219
construction work in progress	216
held for future use	214
in service	204-207
leased to others	213
Plant - utility and accumulated provisions for depreciation amortization and depletion (summary)	201
Pollution control facilities, accumulated deferred income taxes	234
Power Exchanges	326-327
Premium and discount on long-term debt	256
Premium on capital stock	251
Prepaid taxes	262-263
Property - losses, extraordinary	230
Pumped storage generating plant statistics	408-409
Purchased power (including power exchanges)	326-327
Reacquired capital stock	250
Reacquired long-term debt	256-257
Receivers' certificates	256-257
Reconciliation of reported net income with taxable income from Federal income taxes	261
Regulatory commission expenses deferred	233
Regulatory commission expenses for year	350-351
Research, development and demonstration activities	352-353
Retained Earnings	
amortization reserve Federal	119
appropriated	118-119
statement of, for the year	118-119
unappropriated	118-119
Revenues - electric operating	300-301
Salaries and wages	
directors fees	105
distribution of	354-355
officers'	104
Sales of electricity by rate schedules	304
Sales - for resale	310-311
Salvage - nuclear fuel	202-203
Schedules, this report form	2-4
Securities	
exchange registration	250-251
holders and voting powers	106-107
Statement of Cash Flows	120-121
Statement of income for the year	114-117
Statement of retained earnings for the year	118-119
Steam-electric generating plant statistics	402-403
Stock liability for conversion	252
Substations	426
Supplies - materials and	227

INDEX (Continued)

Schedule	Page No.
Taxes	
accrued and prepaid	262-263
charged during year	262-263
on income, deferred and accumulated	234
	272-277
reconciliation of net income with taxable income for	261
Transformers, line - electric	429
Transmission	
lines added during year	424-425
lines statistics	422-423
of electricity for others	328-330
of electricity by others	332
Unamortized	
debt discount	256-257
debt expense	256-257
premium on debt	256-257
Unrecovered Plant and Regulatory Study Costs	230

PECO ENERGY COMPANY ELECTRIC OPERATIONS
ENERGY COST ADJUSTMENT - STATEMENT NO. 6 - QUARTERLY REPORT NO. 4
Report for the period ending March 31, 1996
Summary of Energy Output, Sales, and Costs by Fuel Type
Sched. 5B: Fuel Costs of Major Units by Fuel Type-- $$ -- Page 1 of 2

NUCLEAR	APR95	MAY95	JUN95	JUL95	AUG95	SEP95	OCT95	NOV95	DEC95	JAN96	FEB96	MAR96	TOTAL
Limerick #1	$3,407,875	$2,709,031	$3,417,522	$3,412,704	$2,232,367	$1,418,171	$3,586,348	$3,477,093	$3,545,975	$3,202,599	$407,495	$2,674,862	$33,492,042
Limerick #2	$3,472,979	$3,290,019	$3,343,093	$3,611,414	$3,024,977	$3,481,359	$3,691,850	$3,487,612	$3,624,588	$3,593,089	$3,457,920	$3,664,756	$41,743,656
Peach Bottom #2	$1,423,258	$1,452,316	$1,616,994	$1,919,801	$1,924,342	$2,173,573	$2,267,601	$1,565,563	$1,247,165	$1,703,910	$1,726,542	$1,709,733	$20,730,798
Peach Bottom #3	$2,446,111	$2,178,243	$1,885,726	$1,458,244	$1,249,783	$550,688	$543,876	$1,673,464	$1,841,300	$2,109,966	$1,707,584	$2,118,176	$19,763,161
Salem #1	$1,908,132	$849,913	($68,640)	$77,259	$66,300	$66,300	$85,484	$85,485	$85,485	$85,485	$85,485	$85,484	$3,412,172
Salem #2	$1,901,095	$2,319,637	$44,386	$68,072	$49,596	$49,596	$63,947	$63,947	$63,947	$63,947	$63,947	$63,947	$4,816,064
Fuel oil	($15,393)	($2,650)	$10,236	$5,568	$20,647	$4,197	$8,143	$157,514	$85,169	$3,145	$754	$438	$277,768
Subtotal	$14,544,056	$12,796,509	$10,249,317	$10,553,062	$8,568,012	$7,743,884	$10,247,249	$10,510,678	$10,493,629	$10,762,141	$7,449,727	$10,317,396	$124,235,660
MINEMOUTH COAL													
Conemaugh #1,#2	$2,271,783	$2,471,312	$2,681,115	$2,411,053	$2,402,884	$1,489,955	$1,375,945	$1,798,323	$2,630,063	$2,500,461	$2,269,129	$2,543,040	$26,845,063
Keystone #1,#2	$2,391,632	$3,212,196	$3,199,412	$3,103,923	$2,771,812	$3,136,398	$3,071,761	$3,006,002	$3,498,875	$3,073,079	$2,721,637	$2,016,532	$35,203,259
Subtotal	$4,663,415	$5,683,508	$5,880,527	$5,514,976	$5,174,696	$4,626,353	$4,447,706	$4,804,325	$6,128,938	$5,573,540	$4,990,766	$4,559,572	$62,048,322
URBAN COAL													
Eddystone #1,#2	$2,539,802	$1,469,824	$1,258,015	$678,435	$1,991,007	$2,745,709	$4,132,826	$4,455,325	$5,551,908	$4,757,666	$4,768,759	$4,787,101	$39,136,377
Cromby #1	$1,104,396	$949,232	$999,330	$1,114,671	$1,328,377	$1,212,927	$1,317,596	$1,227,439	$1,407,887	$1,363,229	$919,095	$1,301,277	$14,245,456
Subtotal	$3,644,198	$2,419,056	$2,257,345	$1,793,106	$3,319,384	$3,958,636	$5,450,422	$5,682,764	$6,959,795	$6,120,895	$5,687,854	$6,088,378	$53,381,833
No. 6 OIL													
Schuylkill #1		$567,320	$0		$3,747,013	$115,280	($1,292)	$71	$1,315,787	$1,411,346	$518,159	($122,417)	$7,551,267
Eddystone #3,#4	$28,476	$22,233	$321,315	$893,348	$1,368,605	$328,741	$313,285	$588,867	$3,804,153	$5,234,084	$3,809,729	$1,753,419	$18,466,255
Cromby #2	$22,528	$43,586	$55,409		$68,707	$65,065	$161,966	$69,709	$73,192	$1,233,916	$2,084,031	$1,562,913	$5,441,022
Delaware #7,#8	$27,661	$24,185	$494,840	$2,242,208	$1,586,444	$118,269		$1,487	$1,050,441	$1,572,827	$1,457,395	$1,196,312	$9,772,069
Subtotal	$78,665	$657,324	$871,564	$3,135,556	$6,770,769	$627,355	$473,959	$660,134	$6,243,573	$9,452,173	$7,869,314	$4,390,227	$41,230,613
No. 2 OIL													
Schuylkill #1		$2,285	$0	$81,053					$3,177	$0	($1,133)	$0	$85,382
Eddystone #3,#4	$5,621	$51,611	$63,313	$33,995	$49,136	$8,874	$58,354	$38,388	$184,746	$900,267	$606,300	$415,790	$2,416,395
Cromby #1		$46,262	$19,084	$11,510	$7,060	$21,959	$16,977	$57,118	$26,869	$254,956	$75,230	$88,721	$625,746
Delaware #7,#8	$13,401	$12,897	$18,308	$19,042	$10,547	$6,560	$11,285	$39,993	$65,325	$85,186	$57,626	$3,963	$344,133
Conemaugh #1,#2	$5,970	$3,380	$545	$6,590	$3,959	($1,183)		$22,247	$2,673	$9,316	$8,710	$5,621	$67,828
Keystone #1,#2	$5,232	$35,154	($104,604)	($28,443)	$59,726	($4,073)	($31,178)	($26,550)	($111,966)	$74,253	($7,318)	($2,232)	($141,999)
Subtotal	$30,224	$151,589	($3,354)	$123,747	$130,428	$32,137	$55,438	$131,196	$170,824	$1,323,978	$739,415	$511,863	$3,397,485
NATURAL GAS	incl. Feb Adj (1,470,476)												
Conemaugh #1,#2	$10,718	$7,030	$1,889	$46,007	$75,764	$3,121	$1,970	$15,384	$4,333	$40,496	$14,097	$8,141	$228,950
Eddystone #1,#2	$144,653	$57,298	$67,604	($1,918)	($50,124)	($27,125)	$339,035	$1,382,502	$554,062	$966,371	$822,138	$118,715	$4,373,211
Eddystone #3,#4	($470,394)	$3,561,839	$2,065,251	$5,735,110	$5,873,465	$4,101,788	$2,747,172	($72,026)	$270,497	$427,071	($28,355)	$820,275	$25,031,693
Cromby #2	$1,230,780	$1,053,000	$2,212,230	$1,899,050	$1,791,997	$1,597,994	$424,555	$105,719	$106,576	$599,079	($62,346)	$673,719	$11,632,353
Subtotal	$915,757	$4,679,167	$4,346,974	$7,678,249	$7,691,102	$5,675,778	$3,512,732	$1,431,579	$935,468	$2,033,017	$745,534	$1,620,850	$41,266,207
INTERNAL COMB.	$44,100	$19,218	$222,906	$2,089,238	$3,815,709	$582,069	$345,518	$852,705	$1,421,123	$1,509,209	$1,250,164	$1,269,984	$13,421,943
TOTAL	$23,920,415	$26,406,371	$23,825,279	$30,887,934	$35,470,100	$23,246,212	$24,533,024	$24,073,381	$32,353,350	$36,774,953	$28,732,774	$28,758,270	$338,982,063

Attachment G-6a

PECO ENERGY COMPANY ELECTRIC OPERATIONS
ENERGY COST ADJUSTMENT - STATEMENT NO. 6 - QUARTERLY REPORT NO. 4
Report for the period ending March 31, 1996
Summary of Energy Output, Sales, and Costs by Fuel Type
Sched. 5B: Fuel Costs of Major Units by Fuel Type-- $$ -- Page 1 of 2

NUCLEAR	APR95	MAY95	JUN95	JUL95	AUG95	SEP95	OCT95	NOV95	DEC95	JAN96	FEB96	MAR96	TOTAL
Limerick #1	$3,407,875	$2,709,031	$3,417,522	$3,412,704	$2,232,367	$1,418,171	$3,586,348	$3,477,093	$3,545,975	$3,202,599	$407,495	$2,674,862	$33,492,042
Limerick #2	$3,472,979	$3,290,019	$3,343,093	$3,611,414	$3,024,977	$3,481,359	$3,691,850	$3,487,612	$3,624,588	$3,593,089	$3,457,920	$3,664,756	$41,743,656
Peach Bottom #2	$1,423,258	$1,452,316	$1,616,994	$1,919,801	$1,924,342	$2,173,573	$2,267,601	$1,565,563	$1,247,165	$1,703,910	$1,726,542	$1,709,733	$20,730,798
Peach Bottom #3	$2,446,111	$2,178,243	$1,885,726	$1,458,244	$1,249,783	$550,688	$543,876	$1,673,464	$1,841,300	$2,109,966	$1,707,584	$2,118,176	$19,763,161
Salem #1	$1,908,132	$849,913	($68,640)	$77,259	$66,300	$66,300	$85,484	$85,485	$85,485	$85,485	$85,485	$85,484	$3,412,172
Salem #2	$1,901,095	$2,319,637	$44,386	$68,072	$49,596	$49,596	$63,947	$63,947	$63,947	$63,947	$63,947	$63,947	$4,816,064
Fuel oil	($15,393)	($2,650)	$10,236	$5,568	$20,647	$4,197	$8,143	$157,514	$85,169	$3,145	$754	$438	$277,768
Subtotal	$14,544,056	$12,796,509	$10,249,317	$10,553,062	$8,568,012	$7,743,884	$10,247,249	$10,510,678	$10,493,629	$10,762,141	$7,449,727	$10,317,396	$124,235,660
MINEMOUTH COAL													
Conemaugh #1,#2	$2,271,783	$2,471,312	$2,681,115	$2,411,053	$2,402,884	$1,489,955	$1,375,945	$1,798,323	$2,630,063	$2,500,461	$2,269,129	$2,543,040	$26,845,063
Keystone #1,#2	$2,391,632	$3,212,196	$3,199,412	$3,103,923	$2,771,812	$3,136,398	$3,071,761	$3,006,002	$3,498,875	$3,073,079	$2,721,637	$2,016,532	$35,203,259
Subtotal	$4,663,415	$5,683,508	$5,880,527	$5,514,976	$5,174,696	$4,626,353	$4,447,706	$4,804,325	$6,128,938	$5,573,540	$4,990,766	$4,559,572	$62,048,322
URBAN COAL													
Eddystone #1,#2	$2,539,802	$1,469,824	$1,258,015	$678,435	$1,991,007	$2,745,709	$4,132,826	$4,455,325	$5,551,908	$4,757,666	$4,768,759	$4,787,101	$39,136,377
Cromby #1	$1,104,396	$949,232	$999,330	$1,114,671	$1,328,377	$1,212,927	$1,317,596	$1,227,439	$1,407,887	$1,363,229	$919,095	$1,301,277	$14,245,456
Subtotal	$3,644,198	$2,419,056	$2,257,345	$1,793,106	$3,319,384	$3,958,636	$5,450,422	$5,682,764	$6,959,795	$6,120,895	$5,687,854	$6,088,378	$53,381,833
No. 6 OIL													
Schuylkill #1		$567,320	$0		$3,747,013	$115,280	($1,292)	$71	$1,315,787	$1,411,346	$518,159	($122,417)	$7,551,267
Eddystone #3,#4	$28,476	$22,233	$321,315	$893,348	$1,368,605	$328,741	$313,285	$588,867	$3,804,153	$5,234,084	$3,809,729	$1,753,419	$18,466,255
Cromby #2	$22,528	$43,586	$55,409		$68,707	$65,065	$161,966	$69,709	$73,192	$1,233,916	$2,084,031	$1,562,913	$5,441,022
Delaware #7,#8	$27,661	$24,185	$494,840	$2,242,208	$1,586,444	$118,269		$1,487	$1,050,441	$1,572,827	$1,457,395	$1,196,312	$9,772,069
Subtotal	$78,665	$657,324	$871,564	$3,135,556	$6,770,769	$627,355	$473,959	$660,134	$6,243,573	$9,452,173	$7,869,314	$4,390,227	$41,230,613
No. 2 OIL													
Schuylkill #1		$2,285	$0	$81,053					$3,177	$0	($1,133)	$0	$85,382
Eddystone #3,#4	$5,621	$51,611	$63,313	$33,995	$49,136	$8,874	$58,354	$38,388	$184,746	$900,267	$606,300	$415,790	$2,416,395
Cromby #1		$46,262	$19,084	$11,510	$7,060	$21,959	$16,977	$57,118	$26,869	$254,956	$75,230	$88,721	$625,746
Delaware #7,#8	$13,401	$12,897	$18,308	$19,042	$10,547	$6,560	$11,285	$39,993	$65,325	$85,186	$57,626	$3,963	$344,133
Conemaugh #1,#2	$5,970	$3,380	$545	$6,590	$3,959	($1,183)		$22,247	$2,673	$9,316	$8,710	$5,621	$67,828
Keystone #1,#2	$5,232	$35,154	($104,604)	($28,443)	$59,726	($4,073)	($31,178)	($26,550)	($111,966)	$74,253	($7,318)	($2,232)	($141,999)
Subtotal	$30,224	$151,589	($3,354)	$123,747	$130,428	$32,137	$55,438	$131,196	$170,824	$1,323,978	$739,415	$511,863	$3,397,485
NATURAL GAS	incl. Feb Adj. ($1,470,476)												
Conemaugh #1,#2	$10,718	$7,030	$1,889	$46,007	$75,764	$3,121	$1,970	$15,384	$4,333	$40,496	$14,097	$8,141	$228,950
Eddystone #1,#2	$144,653	$57,298	$67,604	($1,918)	($50,124)	($27,125)	$339,035	$1,382,502	$554,062	$966,371	$822,138	$118,715	$4,373,211
Eddystone #3,#4	($470,394)	$3,561,839	$2,065,251	$5,735,110	$5,873,465	$4,101,788	$2,747,172	($72,026)	$270,497	$427,071	($28,355)	$820,275	$25,031,693
Cromby #2	$1,230,780	$1,053,000	$2,212,230	$1,899,050	$1,791,997	$1,597,994	$424,555	$105,719	$106,576	$599,079	($62,346)	$673,719	$11,632,353
Subtotal	$915,757	$4,679,167	$4,346,974	$7,678,249	$7,691,102	$5,675,778	$3,512,732	$1,431,579	$935,468	$2,033,017	$745,534	$1,620,850	$41,266,207
INTERNAL COMB.	$44,100	$19,218	$222,906	$2,089,238	$3,815,709	$582,069	$345,518	$852,705	$1,421,123	$1,509,209	$1,250,164	$1,269,984	$13,421,943
TOTAL	$23,920,415	$26,406,371	$23,825,279	$30,887,934	$35,470,100	$23,246,212	$24,533,024	$24,073,381	$32,353,350	$36,774,953	$28,732,774	$28,758,270	$338,982,063

PECO ENERGY COMPANY - ELECTRIC OPERATIONS
ENERGY COST ADJUSTMENT - STATEMENT NO. 7 - QUARTERLY REPORT NO. 1
Report for the period ending Dec. 31, 1996
Summary of Energy Output, Sales, and Costs by Fuel Type
Sched. 5B: Fuel Costs of Major Units by Fuel Type-- $$ -- Page 1 of 2

NUCLEAR	APR96	MAY96	JUN96	JUL96	AUG96	SEP96	OCT96	NOV96	DEC96	JAN97	FEB97	MAR97	TOTAL
Limerick #1	$3,301,246	$3,261,786	$3,453,709	$2,520,511	$3,673,442	$3,545,498	$3,677,797	$3,390,345	$3,634,051				$30,458,385
Limerick #2	$3,478,613	$3,217,594	$3,479,354	$3,670,216	$3,680,037	$3,535,821	$3,457,949	$3,475,254	$1,351,253				$29,346,091
Peach Bottom #2	$1,642,853	$1,420,328	$1,339,836	$834,364	$578,324	($361,393)	$729,731	$1,666,248	$1,741,784				$9,592,075
Peach Bottom #3	$2,041,014	$2,119,147	$1,533,375	$2,398,837	$2,445,166	$2,747,048	$2,400,520	$2,010,241	$2,055,938				$19,751,286
Salem #1	$85,485	$85,485	$85,485	$85,485	$85,485	$207,807	$79,821	$79,821	$79,821				$874,695
Salem #2	$63,947	$63,947	$63,947	$63,947	$63,947	$63,947	$61,829	$61,829	$61,829				$569,169
Fuel oil	$937	$49,015	($17,114)	$0	$0	$2,286	$0	$3,847	$1,408,759				$1,447,730
Subtotal	$10,614,095	$10,217,302	$9,938,592	$9,573,360	$10,526,401	$9,741,014	$10,407,647	$10,687,585	$10,333,435				$92,039,431
MINEMOUTH COAL													
Conemaugh #1,#2	$2,108,507	$2,093,176	$2,479,052	$2,632,204	$2,583,627	$1,487,313	$1,867,054	$2,420,155	$2,433,173				$20,104,261
Keystone #1,#2	$3,289,671	$3,588,565	$3,633,480	$3,679,086	$3,005,372	$3,291,877	$3,192,381	$3,095,088	$3,172,560				$29,948,080
Subtotal	$5,398,178	$5,681,741	$6,112,532	$6,311,290	$5,588,999	$4,779,190	$5,059,435	$5,515,243	$5,605,733				$50,052,341
URBAN COAL													
Eddystone #1,#2	$2,348,849	$2,294,139	$2,351,695	$7,786,946	$5,195,166	$5,391,205	$4,016,926	$4,147,105	$6,430,498				$39,962,529
Cromby #1	$921,292	$1,177,139	$1,005,031	$1,114,434	$1,347,808	$1,129,335	$1,429,392	$259,212	$1,654,619				$10,038,262
Subtotal	$3,270,141	$3,471,278	$3,356,726	$8,901,380	$6,542,974	$6,520,540	$5,446,318	$4,406,317	$8,085,117				$50,000,791
No. 6 OIL													
Schuylkill #1	($513,698)	$284,291	$537,155	$720,706	$313,743	$131,852		$0	$7,283				$1,481,332
Eddystone #3,#4	$252,610	$234,998	$1,865,830	$3,997,925	$2,166,896	$622,975	$1,882,786	$2,351,157	$2,087,886				$15,463,063
Cromby #2	$211,343	$285,601	$796,938	$1,295,918	$133,763	$14,846	$101,271	$21,562	$275,272				$3,136,514
Delaware #7,#8	$16,738	$426,592	$829,436	$1,127,383	$826,447	$362,409	$3,836	$425,884	$140,879				$4,159,604
Subtotal	($33,007)	$1,231,482	$4,029,359	$7,141,932	$3,440,849	$1,132,082	$1,987,893	$2,798,603	$2,511,320				$24,240,513
No. 2 OIL													
Schuylkill #1	$2,754	$5,071	$1,945	$1,969	$694	$239		$29	$288				$12,989
Eddystone #3,#4	$165,214	$114,396	$132,527	$300,449	$285,384	$257,547	$183,699	$150,215	$78,194				$1,667,625
Cromby #1	$80,024	$30,615	$22,184	$36,840	$20,747	$115,801	$13,786	$48,651	$24,861				$393,509
Delaware #7,#8	$24,836	$13,706	$25,172	$11,253	$17,793	$13,926	$27,073	$46,393	$68,907				$249,059
Conemaugh #1,#2	$11,534	$20,865	$8,522	$6,545	$3,286	$3,871	$6,127	$0	$7,420				$68,170
Keystone #1,#2	$48,623	$7,193	$2,234	$1,665	$27,882	$9,684	$10,033	$4,527	$16,431				$128,272
Subtotal	$332,985	$191,846	$192,584	$358,721	$355,786	$401,068	$240,718	$249,815	$196,101				$2,519,624
NATURAL GAS													
Conemaugh #1,#2	$8,349	$18,670	$9,501	$11,002	$5,113	$6,277	$25,247	$13,913	$12,949				$111,021
Eddystone #1,#2	$670,374	$636,966	$205,599	$79,448	$648,636	$514,489	$599,653	$349,483	($152,662)				$3,551,986
Eddystone #3,#4	$369,813	$682,260	$41,049	$142,587	$1,032,923	($460,380)	$655,289	$1,149,913	$76,036				$3,689,490
Cromby #2	$174,428	$482,486	$501,568	$59,118	$1,366,252	$310,941	$104,684	$152,535	($339,207)				$2,812,805
Subtotal	$1,222,964	$1,820,382	$757,717	$292,155	$3,052,924	$371,327	$1,384,873	$1,665,844	($402,884)				$10,165,302
INTERNAL COMB.	$414,629	$719,881	$516,597	$1,181,029	$782,944	$1,691,461	$1,530,334	$1,206,155	$2,218,676				$10,261,706
TOTAL	$21,219,985	$23,333,912	$24,904,107	$33,759,867	$30,290,877	$24,636,682	$26,057,218	$26,529,562	$28,547,498				$239,279,708

Attachment G-6b

PECO ENERGY COMPANY - ELECTRIC OPERATIONS
ENERGY COST ADJUSTMENT - STATEMENT NO. 7 - QUARTERLY REPORT NO. 1
Report for the period ending Dec. 31, 1996
Summary of Energy Output, Sales, and Costs by Station
Sched. 5B: Fuel Cost Summary by Major Units -- $$ -- Page 2 of 2

NUCLEAR	APR96	MAY96	JUN96	JUL96	AUG96	SEP96	OCT96	NOV96	DEC96	JAN97	FEB97	MAR97	TOTAL
Limerick #1	$3,301,246	$3,261,786	$3,453,709	$2,520,511	$3,673,442	$3,545,498	$3,677,797	$3,390,345	$3,634,051				$30,458,385
Limerick #2	$3,478,613	$3,217,594	$3,479,354	$3,670,216	$3,680,037	$3,535,821	$3,457,949	$3,475,254	$1,351,253				$29,346,091
Peach Bottom #2	$1,642,853	$1,420,328	$1,339,836	$834,364	$578,324	($361,393)	$729,731	$1,666,248	$1,741,784				$9,592,075
Peach Bottom #3	$2,041,014	$2,119,147	$1,533,375	$2,398,837	$2,445,166	$2,747,048	$2,400,520	$2,010,241	$2,055,938				$19,751,286
Salem #1	$85,485	$85,485	$85,485	$85,485	$85,485	$207,807	$79,821	$79,821	$79,821				$874,695
Salem #2	$63,947	$63,947	$63,947	$63,947	$63,947	$63,947	$61,829	$61,829	$61,829				$569,169
Fuel oil	$937	$49,015	($17,114)	$0	$0	$2,286	$0	$3,847	$1,408,759				$1,447,730
Subtotal	$10,614,095	$10,217,302	$9,938,592	$9,573,360	$10,526,401	$9,741,014	$10,407,647	$10,687,585	$10,333,435				$92,039,431
MINEMOUTH COAL													
Conemaugh #1,#2	$2,128,390	$2,132,711	$2,497,075	$2,649,751	$2,592,026	$1,497,461	$1,898,428	$2,434,068	$2,453,542				$20,283,452
Keystone #1,#2	$3,338,294	$3,595,758	$3,635,714	$3,680,751	$3,033,254	$3,301,561	$3,202,414	$3,099,615	$3,188,991				$30,076,352
Subtotal	$5,466,684	$5,728,469	$6,132,789	$6,330,502	$5,625,280	$4,799,022	$5,100,842	$5,533,683	$5,642,533				$50,359,804
URBAN COAL													
Eddystone #1,#2	$3,019,223	$2,931,105	$2,557,294	$7,866,394	$5,843,802	$5,905,694	$4,616,579	$4,496,588	$6,277,836				$43,514,515
Cromby #1	$1,001,316	$1,207,754	$1,027,215	$1,151,274	$1,368,555	$1,245,136	$1,443,178	$307,863	$1,679,480				$10,431,771
Subtotal	$4,020,539	$4,138,859	$3,584,509	$9,017,668	$7,212,357	$7,150,830	$6,059,757	$4,804,451	$7,957,316				$53,946,286
OIL & GAS													
Schuylkill #1	($510,944)	$289,362	$539,100	$722,675	$314,437	$132,091	$0	$29	$7,571				$1,494,321
Eddystone #3,#4	$787,637	$1,031,654	$2,039,406	$4,440,961	$3,485,203	$420,142	$2,721,774	$3,651,285	$2,242,116				$20,820,178
Cromby #2	$385,771	$768,087	$1,298,506	$1,355,036	$1,500,015	$325,787	$205,955	$174,097	($63,935)				$5,949,319
Delaware #7,#8	$41,574	$440,298	$854,608	$1,138,636	$844,240	$376,335	$30,909	$472,277	$209,786				$4,408,663
Subtotal	$704,038	$2,529,401	$4,731,620	$7,657,308	$6,143,895	$1,254,355	$2,958,638	$4,297,688	$2,395,538				$32,672,481
INTERNAL COMB.	$414,629	$719,881	$516,597	$1,181,029	$782,944	$1,691,461	$1,530,334	$1,206,155	$2,218,676				$10,261,706
TOTAL	$21,219,985	$23,333,912	$24,904,107	$33,759,867	$30,290,877	$24,636,682	$26,057,218	$26,529,562	$28,547,498				$239,279,708

PECO Energy Company- Electric Operations
Energy Cost Adjustment - Statement No. 7
Nuclear and Coal Unit Outages
For the Period: January 1,1995 Through December 31, 1997
Schedule 7

Unit Name	PE Share of MW Capacity (1)	Fuel Type	Start Date	Completion Date	# Of Day Duration (2)	MWh Reduction (1)x(2)	Nature Of Outage
Salem 2	471	Nuclear	01/01/95	02/03/95	34	16,014	Scheduled Extension- 8th Refuel
Eddystone 3	279	Coal	01/23/95	02/04/95	12	80,352	Inspect and Repair ABC Condensate Pump Motor
Limerick 2	1,055	Nuclear	01/27/95	02/19/95	23	24,101	Planned 2R03 Refuel
Keystone 1	179	Coal	01/30/95	04/10/95	70	300,720	Periodic Inspection NOx/Acid rain Controls
Salem 2	471	Nuclear	02/03/95	02/16/95	12	5,716	Forced- Solid State Design Inadequacies
Salem 1	471	Nuclear	02/03/95	02/20/95	17	7,790	Forced- Solid State Design Inadequacies
Eddystone 1	279	Coal	02/05/95	02/14/95	9	60,264	Investigate Vibration Problem
Eddystone 1	279	Coal	02/14/95	05/25/95	100	669,600	Periodic Inspection SP Turb/Radiant SPHTR, N
Salem 2	471	Nuclear	02/19/95	03/09/95	18	8,264	Forced- Rx Coolant Water Seal Replacement
Salem 1	471	Nuclear	02/20/95	03/02/95	10	4,632	Forced- Main Steam Pressure Control Problem
Eddystone 2	302	Coal	05/12/95	07/25/95	74	536,352	Periodic Inspection
Salem 1	471	Nuclear	05/17/95	09/09/95	115	54,126	Forced- Equipment Reliability and Operationa
Salem 2	471	Nuclear	06/07/95	11/03/95	155	73,005	Forced- Equipment Reliability and Operationa
Eddystone 2	279	Coal	06/09/95	06/25/95	16	107,136	Inspect & Repair Turbine Control Rotor
Eddystone 1	279	Coal	07/10/95	10/06/95	89	589,248	Turbine Water Induction
Limerick 1	1,055	Nuclear	08/20/95	09/01/95	12	13,044	Forced- Replace Failed Fuel Bundle
Salem 1	471	Nuclear	09/09/95	12/14/95	96	45,236	Planned- 12th Refuel
Limerick 1	1,055	Nuclear	09/11/95	09/25/95	14	14,866	Forced- SRV Replacement
Conemaugh 2	176	Coal	09/11/95	11/26/95	76	321,024	Generator Stator Rewind, Reheater Replacemen
Peach Bottom 3	440	Nuclear	09/22/95	10/17/95	24	10,657	Planned- 3R10 Refuel
Eddystone 1	279	Coal	10/14/95	10/24/95	10	66,969	Repair 1st Reheater Leaks
Salem 2	471	Nuclear	11/03/95	12/31/95	59	27,789	Planned- 9th Refuel
Salem 1	471	Nuclear	12/14/95	12/31/95	18	8,478	Forced- Equipment Reliability and Operationa
Salem 2	471	Nuclear	01/01/96	02/06/96	37	17,247	Planned- 9th Refuel (continued from 1995)
Salem 1	471	Nuclear	01/01/96	06/17/96	169	79,599	Projected Extension
Limerick 1	1,055	Nuclear	02/02/96	02/29/96	29	30,595	Planned- 1R06 Refuel
Salem 2	471	Nuclear	02/07/96	09/10/96	215	101,265	Projected Extension
Keystone 2	178	Coal	02/12/96	03/25/96	42	179,424	Periodic Inspection- FWB Replacement
Cromby 1	144	Coal	04/01/96	05/13/96	42	145,152	Periodic Inspection
Peach Bottom 2	464	Nuclear	09/15/96	10/20/96	35	16,240	Planned- 2R11 Refuel
Eddystone 2	302	Coal	10/05/96	10/19/96	14	101,472	Mid Cycle Inspection
Limerick 2	1,115	Nuclear	01/25/97	02/22/97	29	32,335	Planned- 2r04 Refuel
Salem 1	471	Nuclear	02/01/97	03/17/97	45	21,195	Planned- 13th Refuel
Eddystone 1	279	Coal	03/04/97	04/12/97	39	261,144	Periodic Inspection
Keystone 1	179	Coal	03/10/97	04/27/97	46	206,208	Periodic Inspection
Eddystone 2	302	Coal	04/15/97	04/24/97	9	65,232	Mid Cycle Inspection
Peach bottom 3	464	Nuclear	09/15/97	10/20/97	35	16,240	Planned- 3R11 Refuel
Conemaugh 2	176	Coal	09/22/97	11/16/97	55	232,320	Periodic Inspection
Eddystone 2	302	Coal	09/29/97	11/07/97	39	282,672	Periodic Inspection
Salem 2 (1)	480	Nuclear	10/04/97	11/17/97	45	21,600	Planned- 10th Refuel

(1) MWh reduction reflects power uprate from 471 MW to 480 MW on 9/10/96

Attachment G-6c

PECO Energy Company
Response to Filing Requirements

Schedule G-7
Respondent: Thomas P. Hill, Jr.

Q: Provide the most recent Annual Resource Planning Report prepared for the company and the cost analysis covering selection of alternative forms of generating capacity, if not already provided.

Response:

Attachment G-7 is a copy of the Company's most recent Annual Resource Planning Report.

PROPRIETARY INFORMATION

Docket Number R-00973953

Name of Document 1996 Annual Resource Planning Report

Date Document Received 10-16-1997

DOCUMENT CONTAINS

PROPRIETARY INFORMATION

PECO ENERGY

1996 Annual Resource Planning Report Summary

May 1, 1996

TABLE OF CONTENTS

PAGE

Executive Summary 1

Company Contact for Information 3

Description of PECO Energy Company 4

Approach to Integrated Resource Planning 5

Demand Forecasting 7

Preferred Plan 8

Two-Year Implementation Plan 9

Attachment 1: Preferred Plan 10

Attachment 2: System Map 11

Attachment 3: Peak Demand Forecasts 12

Attachment 4: Energy Forecasts 13

NOTE: This summary of the 1996 Annual Resource Planning Report is provided in response to 52 Pa. Code § 57.154.

I. EXECUTIVE SUMMARY

The PECO Energy Company (PECO Energy) Annual Resource Planning Report (ARPR) for the period 1996-2015 represents PECO Energy's current assessment of the most economic allocation of resources available to meet customers' electric energy needs. The evaluation process used to develop this 20 year plan requires numerous projections including estimates of economic growth, inflation, cost of money, sales growth and fuel cost escalation. Since not all of these factors are within the Company's control, this plan must be viewed as a guide that must be regularly reevaluated.

The preferred plan contained in the ARPR anticipates no need to install any new generating facilities during the next 12 years. Resource requirements in that period will be met by productivity improvements to existing resources, demand-side management and existing non-utility generator commitments. However, PECO Energy does project a requirement for 900 MW of new resources, which could be supply side, demand side, or a combination of these, during the 2009-2015 period. The new resources may be built or managed by PECO Energy or by others. During the period 1996 to 2015, PECO Energy expects to require about 1215 MW of additional resources to supply its customers' requirements plus a 20% reserve margin in 2015. The primary change from last year is the addition of a 300 MW resource in 2015, the last year of the plan. The resources identified in the plan include:

Supply Side Changes	MW
Salem 2 capacity increase	8
Limerick 1 & 2 Rotor Replacement	100
Subtotal of Supply Side Changes	108
Demand Side Changes	
Demand-side management (maximum)	24
Associated reserve reduction	5
Subtotal of Demand Side Changes	29
Resource Acquisition	
Non Utility Generation	178
New resources	900
Subtotal of Resource Acquisitions	1078
Total Additional Resources	1215

At the end of the twenty-year study period, PECO Energy's installed capacity will be 41% nuclear, 14% coal, 31% oil or natural gas, and 14% hydro. The energy generated by this installed capacity will be approximately 61% nuclear, 19% coal, 17% gas and oil, and 3% hydro.

The preferred resource plan is selected because it provides the greatest overall benefit under the scenarios studied. The reliance on productivity improvements to existing generation and demand-side management prior to the acquisition of new resources provides maximum flexibility to respond to changing customer requirements.

The ability to provide for our customers' requirements not only requires evaluation of supply and demand side resources, but also review of existing generating facilities. Because no retirements are planned, the average age of PECO Energy generating units will increase significantly by the end of the 20-year period. Although continued operation of existing generating units is critical to the preferred plan, the reliability of very old generation is uncertain. PECO Energy will continue to investigate the feasibility of the service continuation option.

PECO Energy Company's preferred resource plan is included as Attachment 1.

Currently, there are several ongoing or recently completed investigations or initiatives that could impact the Company's ARPR. They are:

1) the restructuring of PJM,
2) the issuance by the Federal Energy Regulatory Commission of a final rulemaking in the Mega NOPR, and
3) the PaPUC investigation into competition.

No impact of these has been reflected in this ARPR as none have taken final form. Future ARPR's will likely include the impact.

II. COMPANY CONTACT FOR INFORMATION

This summary report is available to the public for inspection at PECO Energy's offices during normal business hours. Copies of the summary report are available, without charge, upon written request to the individual listed below. Copies of the ARPR may be purchased from PECO Energy by sending a check for $150, payable to "PECO Energy", to:

Mr. Alfred A. Miller
Director - Rates
PECO Energy Company
2301 Market Street
Philadelphia, PA 19103

III. DESCRIPTION OF PECO ENERGY COMPANY

PECO Energy is an operating utility which provides electric and gas services to customers in southeastern Pennsylvania. The total area served by the Company covers 2,107 square miles. Electric service is supplied in an area of 1,972 square miles with a population of 3,700,000, including 1,600,000 in the City of Philadelphia. Natural gas service is supplied to an area of 1,475 square miles with a population of 1,900,000.

The electric system consists of 17 generating stations in Pennsylvania, New Jersey and Maryland. The total net summer capability of the Company's installed capacity is 9,127 MW. The electric system also includes significant investments in transmission and distribution lines, substations, and other facilities necessary to provide service to all of the Company's customers.

PECO Energy is a member of the Pennsylvania-New Jersey-Maryland Interconnection Association (PJM). The PJM agreement provides for coordination of the bulk power plans of its member systems and reliable operation of their bulk power facilities.

A map of PECO Energy's service territory, showing major generation and transmission facilities within its electric service territory, is included as Attachment 2.

IV. APPROACH TO INTEGRATED RESOURCE PLANNING

The primary objective in the ARPR is to balance supply and demand as conditions change over time. The resources are planned and implemented so that electricity is supplied to the ultimate customers in the most economical manner subject to the constraint that a certain level of reliability of electric supply is needed. This plan simulates which of the possible resource options best meet this objective. The remainder of this section describes this selection process in more detail.

Balancing Supply and Demand

PECO Energy's highest demand occurs during the summer, so the generation reserve over summer peak demand is the measure often used to determine adequacy of supply. This study plans for a reserve over the net peak demand of 21.0% in 1996, 20.5% in 1997 and 20.0% for 1998 and beyond, and assumes that peak demand is reduced by any demand-side management and any interruptible demand. The preferred plan of this study meets the appropriate reserve criteria within a reasonable tolerance throughout the 20-year period.

Supply and demand must balance not only at the highest demand but also at every other time. Demand varies based on customer needs and behaviors. PECO Energy has installed a mixture of generation or supply-side options. Our present mix of generation contains some units that run continuously to meet base demand and other units that run only at certain times to meet peak demands and also contains some units that store energy during off-peak periods for later use during peak periods.

Another way of balancing supply and demand is to modify the demand by influencing the behavior of customers. PECO Energy has existing demand-side management programs, such as off-peak rates and incentives to encourage residential builders to construct energy-efficient homes, which conserve energy and reduce peak demands.

Resource Evaluation Criteria

Evaluating the net benefits of potential resources requires a multi-objective approach in order to balance the interests of participating and non-participating customers, i.e. those customers who are either unable or choose not to participate in a particular DSM program. Therefore, PECO Energy uses a combination of several cost/benefit tests in evaluating its choice of resource options:

Participant Test: the impact on a customer who participates in a chosen DSM program

Total Resource Cost Test: the impact of a resource choice on the average customer's total cost of energy services

Rate Impact Measure Test: the impact of a resource choice on the average price of electricity

Utility Test: the impact of a demand-side or supply-side resource choice on the utility's revenue requirement

This balanced approach to resource selection is designed to yield significant benefits to participating customers while minimizing the impact of relative price increases on non-participating customers.

Resource Options

The ARPR includes discussion of supply-side options. The supply-side items in the preferred plan include productivity improvements for existing generation and continued operation of existing generation.

The 1996 Annual Resource Planning Report incorporates the proposed Demand-Side Management Program plan as filed with the Pennsylvania Public Utility Commission on March 14, 1994. In that program, PECO Energy proposed a number of demand-side management programs for implementation. Because the 1995 DSM Plan has not yet been approved, implementation is assumed to begin in 1996 for purposes of the ARPR.

The report also indicates that, in the long-term, additional supply side or demand side resources , will be necessary to meet customer requirements. These resources will likely be obtained through a competitive bidding process.

Resource Analysis Methodology

In conducting its resource analysis, PECO Energy first develops a list of potential resource options using its judgment and experience. The costs and benefits of each option are analyzed using the revenue requirement methodology. This method combines production cost calculations with capital and operating and maintenance costs to calculate the net benefits of alternative resource mixes. The preferred plan is generally the one which yields the greatest net benefit for the base set of assumptions.

V. DEMAND FORECASTING

Peak Demand Forecasts

The forecasts of annual peak demand are derived from energy and connected air conditioning forecasts. The low, base and high scenarios have compound growth rates of 0.1%, 1.17% and 1.15% per year, respectively, over the 20-year period. Attachment 3 shows the three peak demand forecasts for the next twenty years.

Energy Forecasts

PECO Energy's energy forecast incorporates both end-use and econometric forecasts. Assumptions are first developed which affect all classes of service and then assumptions which specifically apply to each class are developed. This procedure is followed for the median forecast. Alternative high and low forecasts are also developed. The forecast scenarios have compound growth rates of 0.27%, 1.14%, and 1.75% per year, respectively, over the 20-year period. Attachment 4 shows the three energy forecasts for the next twenty years.

VI. PREFERRED PLAN

PECO Energy's preferred plan, which is shown in Attachment 1 of this summary, provides the greatest overall benefits for the base assumptions, as well as allowing flexibility as conditions change over time. The plan incorporates demand-side management, continued operation of all existing PECO Energy generation, capacity from existing non-utility generator agreements, productivity improvements resulting from required capital expenditures at Limerick 1 and Limerick 2 units, a capacity increase of the Salem 2 unit as a result of required station engineering work and acquisition of resources in the years 2009, 2012, 2015.

The results of the preferred plan which are expressed in constant dollars, thus eliminating inflation, show that the real cost of electric service is expected to decrease. This reflects the increasing benefits of PECO Energy's past investment in nuclear generation and other electric facilities which are expected to minimize the impact of rising fuel costs. In actual dollars the preferred plan shows a general increase in the cost to serve our customers over the study period, but in an amount less than the general inflation assumption reflected in the analyses. It should be noted, however, that the costs do not constitute a specific prediction of rates to customers. They assume full recovery of all costs and cost increases and that the Company earns a fair return on its common equity.

VII. TWO YEAR IMPLEMENTATION PLAN

PECO Energy has no new supply resource options under construction. The next new resources are planned for 2009. Therefore, no resource acquisition activity is appropriate during the Two-Year Implementation Plan period.

PECO Energy's DSM Program plan, filed on March 14, 1994, proposes the implementation of a number of programs during 1995. Because the 1995 DSM Plan has not yet been approved, implementation is assumed to begin in 1996 for purposes of the ARPR. Some of the DSM and other conservation and load management programs included in the ARPR are:

Residential

- Rate Incentives (Rates OP, RT)
- Smart Choice/EEE
- Low Income Usage Reduction Program
- Customer Assistant Program
- Energy Conservation Literature
- Bright Ideas

Commercial & Industrial

- Rate Incentives (Night Service Rider, Curtailment Rider, Cooling Thermal Storage Rider, Large Interruptible Load Rider)
- Industrial Audits

Regarding productivity improvements, the Limerick rotors, scheduled to be replaced in 1998 and 1999, require no construction implementation plan as they will be installed during a refueling outage. A capacity increase of Salem 2 will also occur in 1996 as a benefit of required station engineering work.

As seen from above, there is no implementation activity for resources during 1996-1997. All schedules assume the timely receipt of required approvals from regulatory agencies.

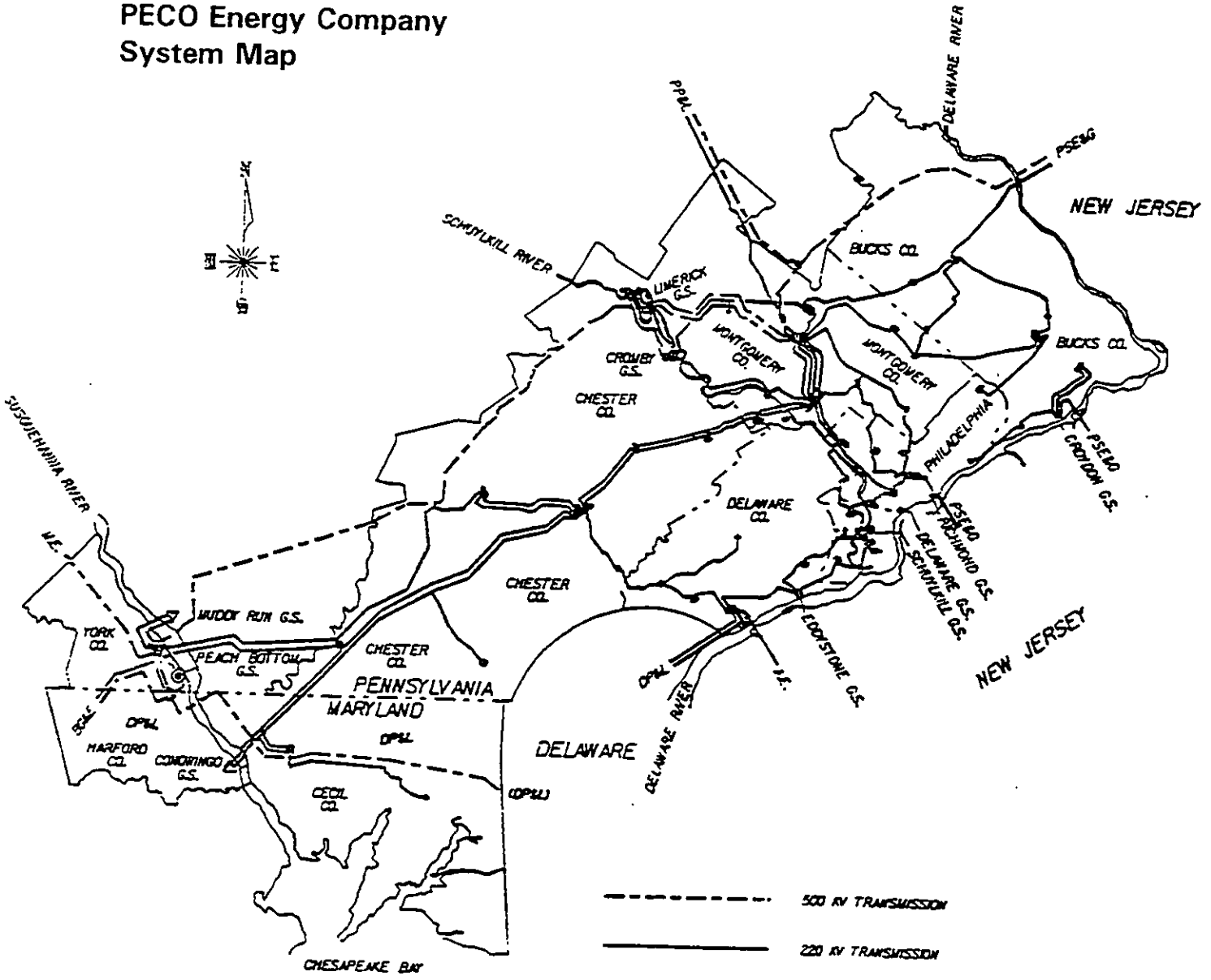
Attachment 1

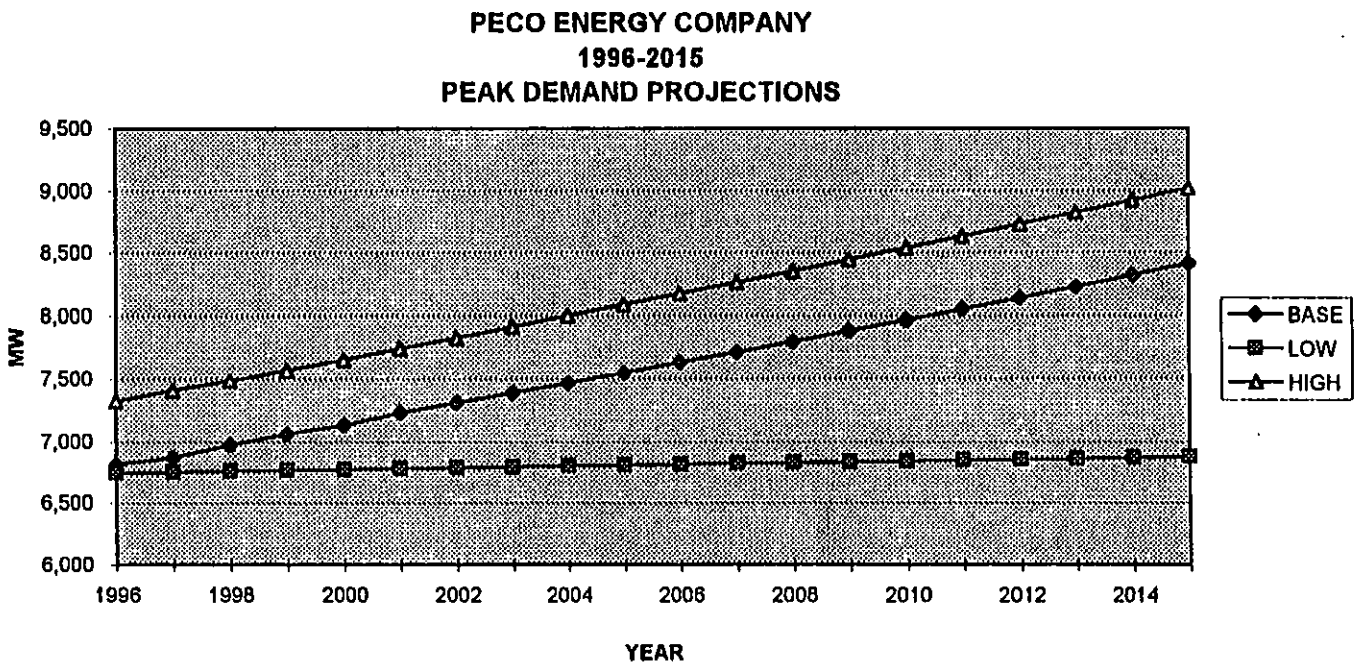
PECO ENERGY COMPANY
1996-2015 CAPACITY AND DEMAND PROJECTION

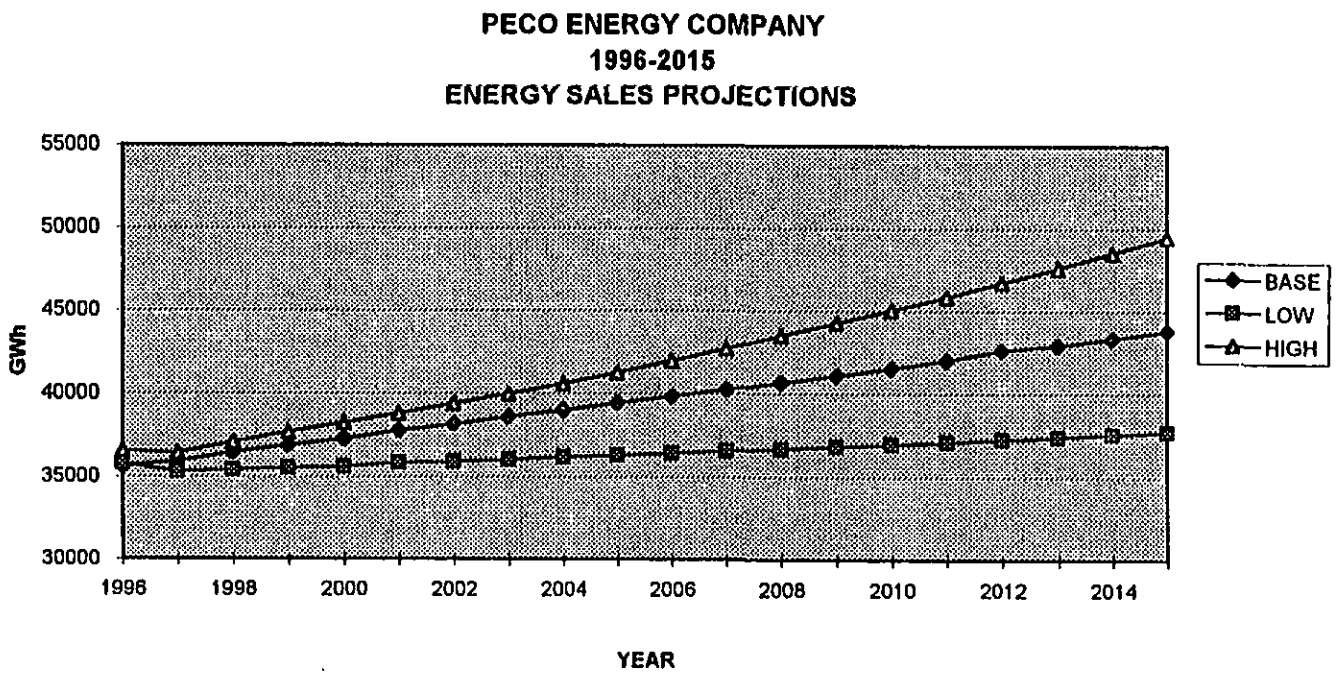
Capacity				Demand			
Year	Change		Total	Gross Peak	Interr	DSM	Net
1995			9068				
1996	60	Limerick 1 Uprate					
	-205	Delmarva P&L Sale					
	-145	TOTAL	8923	7015	204	0	6811
1997	28	MMLP					
	8	Salem 2					
	-7	Delmarva P&L Sale					
	29	TOTAL	8952	7074	204	2	6868
1998	-5	Delmarva P&L Sale					
	-125	Atlantic Electric Sale					
	50	Limerick 1 Rotors					
	150	Grays Ferry					
	-140	BG&E					
	-70	TOTAL	8882	7183	204	6	6973
1999	-6	Delmarva P&L Sale	8876	7277	204	10	7063
	50	Limerick 2 Rotors					
	44	TOTAL					
2000	-6	Delmarva P&L Sale	8870	7354	204	15	7135
2001	-6	Delmarva P&L Sale					
	125	End Atlantic Electric Sale					
	119	TOTAL	8989	7458	204	21	7233
2002	-6	Delmarva P&L Sale	8983	7536	204	24	7308
2003	-6	Delmarva P&L Sale	8977	7615	204	24	7387
2004	-6	Delmarva P&L Sale	8971	7694	204	24	7466
2005	-6	Delmarva P&L Sale	8965	7775	204	24	7547
2006	259	End Delmarva P&L Sale	9224	7856	204	23	7629
2007	0		9224	7938	204	23	7711
2008	0		9224	8021	204	23	7794
2009	300	Resource Acquisition	9524	8104	204	22	7878
2010	0		9524	8189	204	21	7964
2011	0		9524	8274	204	20	8050
2012	300	Resource Acquisition	9824	8360	204	18	8138
2013	0		9824	8447	204	15	8228
2014	0		9824	8535	204	12	8319
2015	300	Resource Acquisition	10124	8623	204	8	8411

Attachment 2

PECO Energy Company System Map




PECO ENERGY COMPANY
1996-2015
PEAK DEMAND PROJECTIONS
9,500
9,000
8,500
8,000
7,500
7,000
6,500
6,000
MW
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
YEAR
BASE
LOW
HIGH


PECO ENERGY COMPANY
1996-2015
ENERGY SALES PROJECTIONS
55000
50000
45000
40000
35000
30000
GWh
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
YEAR
BASE
LOW
HIGH

PECO Energy Company
Response to Filing Requirements

Schedule G-8
Respondent: Thomas P. Hill, Jr.

Q: Describe the generation planning criteria used by the company. Provide any reports or documents that characterize the generation planning criteria. Describe any changes made or contemplated as a result of restructuring.

Response:

Refer to the Direct Testimony of Gregory A. Cucchi.