THIS FILING IS			
Item 1: ☐	An Initial (Original) Submission	OR	☒ Resubmission No.

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)

Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)

Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 1/3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. 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 these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Public Service Electric and Gas Company	**End of** 2025/Q4

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION		
01 Exact Legal Name of Respondent Public Service Electric and Gas Company		02 Year/Period of Report End of 2025/Q4
03 Previous Name and Date of Change (if name changed during year)		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 80 Park Plaza, Newark, New Jersey 07102		
05 Name of Contact Person Viet H. Ngo		06 Title of Contact Person Managing Counsel - Federal Regulatory
07 Address of Contact Person (Street, City, State, Zip Code) 80 Park Plaza, Newark, New Jersey 07102		
08 Telephone of Contact Person, Including Area Code (202) 460-9356	09 This Report Is (1) ☐ An Original (2) ☒ A Resubmission	10 Date of Report (Mo, Da, Yr) *5/6/2026*

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	**04 Date Signed (Mo, Da, Yr)**
Rose M. Chernick		
02 Title Vice President and Controller	Rose M. Chernick	5/6/2026

Title 18, U.S.C. 1001 makes it a crime for any person to 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	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) 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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106 (a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122 (a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	Not Applicable
16	Electric Plant In Service	204-207	Resub 05-06-26
17	Electric Plant Leased to Others	213	Not Applicable
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progres-Electirc	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances and Environmental Credits	228(ab)-229(ab)	Not Applicable
24	Extraordinary Property Losses	230	Not Applicable
25	Unrecovered Plant and Regulatory Study Costs	230	None
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expenses	254	Not Applicable
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) 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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	Not Applicable
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	Not Applicable
44	Sales of Electricity by Rate Schedules	304	
45	Sales of Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	Not Applicable
50	Transmission of Electricity by Others	332	Not Applicable
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	Resub 05-06-26
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	Resub 05-06-26
57	Amounts Included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Statements	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	Not Applicable
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402-403	Not Applicable
64	Hydroelectric Generating Plant Statistics	406-407	Not Applicable
65	Pumped Storage Generating Plant Statistics	408-409	Not Applicable
66	Generating Plant Statistics Pages	410-411	

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) 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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
66.1	Energy Storage Operations (Large Plants)	414	None
66.2	Energy Storage Operations (Small Plants)	419	None
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: ■ Two copies will be submitted ☐ No annual report to stockholders is prepared		

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 office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

   Rose M. Chernick, Vice President and Controller
   Public Service Electric and Gas Company 80 Park Plaza, Newark, New Jersey 07102

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.

   New Jersey, July 15, 1924, under "An Act Concerning Corporations" (Revision of 1896)

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.

   N/A

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

   PSE&G is a New Jersey corporation, incorporated in 1924, and has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102. PSE&G is an operating public utility company engaged principally in the transmission and distribution of electric energy and the distribution of gas in New Jersey to residential, commercial and industrial customers. PSE&G also earns revenue but no margins from commodity sales in its role as provider of last resort for electric and gas.
   PSE&G also offers appliance services and repairs to customers throughout its service territory.
   In addition to our current utility products and services, PSE&G has implemented several programs to improve efficiencies in customer energy use and increase the level of renewable generation within New Jersey.

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

   (1) ☐ Yes...Enter the date when such independent accountant was initially engaged:

   (2) ☒ No

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

All of the issued and outstanding Common Stock of the Respondent is held by Public Service Enterprise Group Incorporated, a New Jersey Corporation, with its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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	New Jersey Properties, Inc.	Real Estate	100%	
2	Public Service Corporation of New Jersey	Research and Development	100%	
3	Public Service New Millennium Econ. Dev. Fund	Economic Development	99%	(1)
4	PSEG Area Development L.L.C.	Economic Development	100%	
5	PSEG Urban Renewal Entity L.L.C.	Economic Development		(2)
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15	Note:			
16	(1) Public Service Corporation of NJ owns 1%			
17	(2) Subsidiary of PSEG Area Development LLC			
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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 policy making 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)	Date Started in Period (d)	Date Ended in Period (e)
1	Chair of the Board - President and CEO	Ralph LaRossa (1)			
2	President and Chief Operating Officer	Kim C. Hanemann	802,100		
3	Executive Vice President and CFO	Daniel J. Cregg (1)			
4	Executive Vice President and General Counsel	Grace Park (1)			
5	Vice President and Controller	Rose Chernick (1)			
6	Vice President and Treasurer	Bradford Huntington (1)			
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15	(1) These individuals are employees of PSEG Services Corporation who charge PSE&G and other affiliates within the consolidated PSEG group for the cost of their services based on approved cost allocation methodologies.				
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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)	Member of the Executive Committee? (c)	Chairman of the Executive Committee? (d)
1	Ralph LaRossa (Chair of the Board and Chief Exec Officer)	80 Park Plaza, Newark, NJ 07102		TRUE
2	Susan Tomasky	Retired President, AEP Transmission of American Electric Power Corporation, Columbus, OH	TRUE	
3	Barry Ostrowsky	Retired President and CEO of RWJBarnabas Health, Inc., West Orange, New Jersey	TRUE	
4	Willie Deese	Retired EVP of Merck & Co., Inc. and President, Merck Manufacturing Division, Kenilworth, New Jersey	TRUE	
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	■ Yes ☐ No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	PJM Open Access Transmission Tariff ("PJM OATT")	
2	—	—
3	Attachment H-10 of PJM OATT	Docket No. ER08-1233
4	—	(initial and compliance filings of formula rate tariff sheets)
5	—	—
6	Attachment H-10 of PJM OATT	Docket No. ER09-249 (incentive filing)
7	—	—
8	Attachment H-10 of PJM OATT	Docket No. ER10-159 (incentive filing)
9	—	—
10	Attachment H-10 of PJM OATT	Docket No. ER11-3352 (incentive filing)
11	—	—
12	Attachment H-10 of PJM OATT	Docket No. ER12-296 (incentive filing)
13	—	—
14	Attachment H-10 of PJM OATT	Docket No. ER12-2274 (abandonment filing)
15	—	—
16	Attachment H-10 of PJM OATT	Docket No. ER14-621
17	—	(Post-Employment Benefits other than Pension ("PBOP")
18	—	- revised tariff sheets)
19	—	—
20	Attachment H-10 of PJM OATT	Docket No. ER14-1608 (incentive filing)
21	—	—
22	Attachment H-10 of PJM OATT	Docket No. ER15-2397
23	—	(Post-Employment Benefits other than Pension ("PBOP")
24	—	- revised tariff sheets)
25	—	—
26	Attachment H-10 of PJM OATT	Docket No. ER16-619 (abandonment filing)
27	—	—
28	Attachment H-10 of PJM OATT	Docket No. ER19-204
29	—	(income tax-related revisions relating to the effects of the TCJA
30	—	- revised tariff sheets)
31	—	—
32	Attachment H-10 of PJM OATT	Docket No. ER22-81
33	—	(Settlement Agreement Compliance Filing - revised tariff sheets)
34	—	—
35	Attachment H-10 of PJM OATT	Docket No. ER23-2916 (abandonment filing)
36	—	—
37	Attachment H-10 of PJM OATT	Docket No. ER20-2004 (Order No. 864 Compliance Filing)
38	—	—
39	—	—
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	■ Yes ☐ No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date /Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20250616-5102	06/16/2025	ER09-1257-000	2024 Formula Rate Annual True-Up Adjustment	PJM OATT Attachment H-10
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3	20251015-5157	10/15/2025	ER09-1257-000	2026 Formula Rate Annual Update	PJM OATT Attachment H-10
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
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INFORMATION ON FORMULA RATES
Formula Rate Variances

If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No (d)
1	323	Electric Operations & Maintenance Expense	b	197
2	323	Electric Operations & Maintenance Expense	c	197
3				
4				
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FOOTNOTE DATA

Schedule Page: 106b Line No.: 1 Column: d

PSE&G's formula rate filing reduces the 2025 Form 1 balance by $105,762 for item that should have been recorded to another FERC Account and not recovered in the formula rate.

Schedule Page: 106b Line No.: 2 Column: d

PSE&G's formula rate filing reduces the 2024 Form 1 balance by $129,595 for item that should have been recorded to another FERC Account and not recovered in the formula rate.

IMPORTANT CHANGES DURING THE QUARTER/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 therefore 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 condition. 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 104 or 105 of the Annual Report Form No. 1, 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.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

Inquiry 1:NONE

Inquiry 2: NONE

Inquiry 3: NONE

Inquiry 4: NONE

Inquiry 5: NONE

Inquiry 6:

By Order dated November 21, 2025, the New Jersey Board of Public Utilities (BPU) has authorized PSE&G to issue long-term debt (i) of not more than $4.575 billion and (ii) as necessary to refinance outstanding amounts at a cost savings or more efficient management of its capital structure, from January 1, 2026 through December 31, 2027. (See IMO Petition of Public Service Electric and Gas Company, Docket No. EF25070383).

In 2025, through December 31st, PSE&G has issued and paid the following amount of long-term debt:

- issued $400 million of 5.05% Secured Medium-Term Notes, Series Q, due March 2035
- issued $500 million of 5.50% Secured Medium-Term Notes, Series Q, due March 2055
- issued $450 million of 4.90% Secured Medium-Term Notes, Series Q, due August 2035, and
- retired $350 million of 3.00% Secured Medium-Term Notes, Series K, at maturity

Subsequent to December 31st, 2025, PSE&G has issued and paid the following amount of long-term debt:

- issued $500 million of 4.20% Secured Medium-Term Notes, Series R, due January 2031
- issued $500 million of 5.63% Secured Medium-Term Notes, Series R, due January 2056, and
- retired $450 million of 0.95% Secured Medium-Term Notes, Series N, at maturity.

By Order dated November 21, 2024, the BPU has authorized PSE&G to issue and have outstanding at any one time up to $1 billion of short-term debt through January 4, 2027. (See IMO Petition of Public Service Electric and Gas Company, Docket No. EF24060403).

As of December 31st, PSE&G had $325 million in Commercial Paper and $26 million of letters of credit outstanding.

In March 2026, PSE&G executed a two-year extension to its existing $1 billion revolving credit facility, extending the maturity through March 2031.

Inquiry 7: NONE

Inquiry 8:

The average non-represented wage scale saw a 3.5% increase effective March 17, 2025. The represented employees of PSE&G saw a 3.0% increase effective May 1, 2025.

Inquiry 9:

REGULATORY ISSUES

In the ordinary course of our business, we are subject to regulation by, and are party to various claims and regulatory proceedings with FERC, the BPU, the Commodity Futures Trading Commission (CFTC) and various state and federal environmental regulators, among others. For information regarding material matters, other than those discussed below, see Note 11. Commitments and Contingent Liabilities. In addition, information regarding PSE&G's specific filings pending before the BPU is discussed in Note 4. Regulatory Assets and Liabilities.

Federal Regulation

FERC is an independent federal agency that regulates the transmission of electric energy and natural gas in interstate commerce and the sale of electric energy and natural gas at wholesale pursuant to the FPA and the Natural Gas Act. PSE&G is a public utility as defined by the FPA. FERC has extensive oversight over such public utilities. FERC approval is usually required when a public utility seeks to: sell or acquire an asset that is regulated by FERC (such as a transmission line or a generating station); collect costs from customers associated with a new transmission facility; charge a rate for wholesale sales under a contract or tariff; or engage in certain mergers and internal corporate reorganizations.

FERC also regulates RTOs/ISOs, such as PJM, and their regional transmission planning processes as well as their energy and capacity markets.

Transmission Regulation

FERC has exclusive jurisdiction to establish the rates and terms and conditions of service for interstate transmission. We currently have FERC-approved formula rates in effect to recover the costs of our transmission facilities. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are subsequently trued up to reflect actual annual expenses and capital expenditures.

Transmission Rate Proceedings and ROE—From time to time, various matters are pending before FERC relating to, among other things, transmission planning and transmission rates and returns, including incentives. Depending on their outcome, any of these matters could materially impact our results of operations and financial condition.

In a rulemaking proceeding issued in 2021, FERC proposed to eliminate the existing 50 basis point adder for RTO membership, which is currently available to PSE&G and other transmission owners in RTOs. Elimination of the RTO adder for RTO membership would reduce PSE&G's annual Net Income and annual cash inflows by approximately $40 million.

Transmission Planning Proceedings—In May 2024, FERC issued a Final Rule to reform regional transmission planning and cost allocation. This order requires transmission providers like PJM to engage in long-term regional planning of not less than 20 years. It also requires certain reforms to the local planning process, including enhancing the transparency of that process and evaluating whether local transmission facilities that need replacing can be "right-sized" to meet broader regional needs.

In December 2025, both PJM and its Transmission Owners made compliance filings at FERC seeking to implement the Final Rule's requirements, including establishing a comprehensive set of long-term transmission needs based on a 20-year planning horizon, providing a role for the states in identifying needs and solutions, and establishing procedures for identifying and planning "right-sized" replacement facilities. If approved by FERC, these changes will provide a regulatory framework for the planning of transmission infrastructure to help address

resource adequacy challenges in PJM. Separately, the PJM Transmission Owners, including PSE&G, are working with the states to develop cost allocation rules to decide who will pay for these long-term transmission facilities, with a FERC filing to be made later in 2026.

In December 2024, a coalition of industrial customers and state ratepayer advocates filed a complaint at FERC against various named public utilities and RTOs/ISOs, including PJM. The complaint alleges that local planning has produced inefficient planning and projects that are not cost-effective, and therefore requests that FERC require the application of regional planning requirements, including relevant competitive solicitation processes, to all transmission facilities over 100kV. The complaint also requests that FERC require RTOs/ISOs to appoint an "Independent System Planner" to oversee transmission planning. While PSEG is not a named party in the complaint, our local planning authority and rights may be impacted by the resolution of this proceeding. We cannot predict the outcome of this proceeding.

On March 6, 2026, FERC issued an order addressing a longstanding dispute about the methodology used in PJM to calculate and assign transmission project costs. The FERC order, among other things, rejected a proposed settlement agreement that would have shifted significant costs to PSE&G's transmission customers. FERC directed PJM to recalculate cost responsibility assignments and resettle billings going back to 2015. Several parties have sought rehearing of the order. PJM has also asked FERC for a lengthy extension of time to recalculate transmission cost responsibility assignments and provide refunds. We cannot predict the outcome of this proceeding.

Regulation of Wholesale Sales—Generation/Market Issues/Market Power

Under FERC regulations, public utilities that wish to sell power at market rates must receive FERC authorization (market-based rate (MBR) authority) to sell power in interstate commerce before making power sales. They can sell power at cost-based rates or apply to FERC for authority to make MBR sales. For a requesting company to receive MBR authority, FERC must first determine that the requesting company lacks market power in the relevant markets and/or that market power in the relevant markets is sufficiently mitigated. Certain PSEG companies are public utilities and currently have MBR authority. These companies, which include PSEG Energy Resources & Trade LLC, PSEG Nuclear LLC and PSE&G must file at FERC every three years to update their market power analyses. At the end of 2025, PSEG filed an updated market power analysis.

In October 2024, FERC issued a Final Rule that eliminates compensation for reactive power in circumstances when the generator is operating within the normal power factor range specified in its interconnection agreement. FERC denied rehearing of this order in June 2025 and in August 2025 accepted a PJM filing that establishes a June 1, 2026 date for elimination of reactive power compensation. In August 2025, PSEG sought judicial review of FERC's decision. This appeal is pending and we cannot predict the outcome. The loss of reactive power compensation is not expected to have a material impact on PSEG's results of operations.

In addition, there are ongoing proceedings at FERC that may impact the interconnection of large loads such as data centers to the power grid, including addressing the issue of what transmission services and charges should be paid by future co-located customers. In February 2025, FERC issued a "show cause" order directing PJM and PJM transmission owners to explain why the PJM tariff is just and reasonable or, alternatively, what revisions might be necessary to address perceived gaps in the PJM tariff with respect to co-located load arrangements. In December 2025, FERC issued an order in this proceeding finding the PJM tariff to be unjust and unreasonable, directing PJM to file tariff revisions to reflect new types of transmission services that will be made available to co-located loads and establishing a paper hearing to set the appropriate level of charges to be paid by co-located load customers.

Relatedly, in October 2025, in response to a directive by the Secretary of Energy, FERC initiated a rulemaking proceeding to establish rules by the end of April 2026 to facilitate the interconnection of large load customers to the transmission system through a queue process. We cannot predict the outcome of these matters.

Compliance

Reliability Standards—PSE&G is required to comply with the North American Electric Reliability Corporation (NERC) Reliability Standards, promulgated by NERC and approved by FERC, which are designed to ensure the

security and reliability of the United States electric transmission and generation system (the "electric grid"). As a result, PSE&G is subject to requirements governing the planning and operation of the electric grid, and requirements governing the physical and cyber security of PSE&G assets that are used to protect and operate the electric grid. Due to the increasing sophistication of physical and cyber security threats to the security and reliability of the electric grid, it is anticipated that FERC and NERC will continue to promulgate new Reliability Standards, and modify existing Reliability Standards, to meet these challenges.

CFTC—In accordance with the Dodd-Frank Wall Street Reform and Consumer Protection Act, the SEC and the CFTC continue to implement a regulatory framework for swaps and security-based swaps. The rules are intended to reduce risk, increase transparency and promote market integrity within the financial system by providing for the registration and comprehensive regulation of swap dealers and by imposing recordkeeping, data reporting, margin and clearing requirements with respect to swaps. We are currently subject to recordkeeping and data reporting requirements applicable to commercial end users. The CFTC finalized rules establishing federal position limits for trading in certain commodities, such as natural gas. Entities such as PSEG began complying with the rules in 2022.

State Regulation

Our principal state regulator is the BPU, which oversees electric and natural gas distribution companies in New Jersey. We are also subject to various other states' regulations due to our operations in those states.

Our New Jersey utility operations are subject to comprehensive regulation by the BPU including, among other matters, regulation of retail electric and gas distribution rates and service, the issuance and sale of certain types of securities and compliance matters.

In addition to base rates, we recover certain costs or earn on certain investments pursuant to mechanisms known as adjustment clauses. These clauses permit the flowthrough of costs to, or the recovery of investments from, customers related to specific programs, outside the context of base rate proceedings. Recovery of these costs or investments is subject to BPU approval for which we make periodic filings. Delays in the pass-through of costs or recovery of investments under these mechanisms could result in significant changes in PSE&G's cash flow. PSE&G's participation in solar, EV and EE programs is also regulated by the BPU, as the terms and conditions of these programs are approved by the BPU. BPU regulation can also have a direct or indirect impact on our power generation business as it relates to energy supply agreements and energy policy in New Jersey.

New Jersey Energy Master Plan (EMP) and Future of Gas Stakeholder Proceeding—In June 2022, the BPU commenced a proceeding to update New Jersey's EMP. An effort was subsequently undertaken during 2023 through early 2025 to create a revised plan, including a series of stakeholder meetings and comments. In March 2025, BPU Staff and a third-party consultant discussed the results of their modeling. The main themes presented were: a need for continued reliability and affordability; challenges for New Jersey to achieve greenhouse gas reduction goals; the new capacity additions that are needed to maintain system reliability, and that these additions can be "clean firm" additions (without details of the meaning of "clean firm"); and the need for new strategies to guide the evolution of natural gas. Following the receipt of additional comments, in November 2025 the BPU released the updated EMP.

The updated EMP included a set of what was presented as "No Regrets" recommendations, described as strategies the state should pursue regardless of any other planning scenarios or steps taken as a broader energy planning strategy. These recommendations include accelerated deployment of clean energy generation sources (for example, solar, wind, advanced nuclear); continued investment in energy efficiency; grid modernization; transportation electrification; workforce development; and expansion of customer assistance programs. In addition to these strategies, the EMP also presents modeling based on 2023-2024 data for alternative pathways to achieve state goals (high electrification, hybrid electrification and remaining at the current state). Given the new administration took office in January 2026, it is not clear how the EMP might influence New Jersey's energy policy and we cannot predict the impact on our business that might result.

Stakeholder Proceeding on Gas Competition, BGSS—In February 2023, the BPU announced that it would open a new docket to conduct a stakeholder proceeding regarding gas supply issues previously raised by competitive gas suppliers, including third-party suppliers' participation in New Jersey gas distribution companies'

annual BGSS filings, and other aspects of the existing BGSS construct. There has been no public activity in this matter since May 2023.

Regional Energy Access (REA) Expansion Project—In September 2024, the United States Circuit Court for the District of Columbia Circuit vacated FERC approval of the REA Expansion Project, which involves a natural gas pipeline running through New Jersey and several other states, and in which PSEG Energy Resources & Trade, LLC, the provider of gas supplies to satisfy PSE&G's BGSS customers, is a customer. The court found that FERC failed to properly consider the environmental consequences of the project, and the alleged lack of market demand for additional natural gas capacity in New Jersey. In January 2025, FERC responded to the Circuit Court's concerns and reinstated its approval of the project. In February 2025, a subset of intervenors filed a rehearing request seeking to overturn FERC's reinstatement of the REA certificate. The same subset of intervenors also filed a motion for an evidentiary hearing. In March 2025, the rehearing request was denied by operation of law, and in August 2025 FERC addressed the arguments raised on rehearing while confirming the denial of the rehearing request and motion for evidentiary hearing.

Energy Efficiency, Triennial Review—In November 2025, BPU Staff issued its straw proposal for the third triennium framework and requirements for energy efficiency programs. The proposed framework suggests changes that, if adopted as proposed, would increase risk to utilities implementing these programs to meet energy efficiency targets that are required by law. PSE&G submitted responsive comments recommending changes to the proposed framework that, if accepted, could better enable optimization of investments and benefits including achieving energy savings targets. Depending on the timing of BPU approval of a final framework, utilities could be expected to file triennium 3 program proposals during 2026 for a program to begin in July 2027. We cannot predict the outcome of this review and straw proposal at this time.

BGS Process—In July 2025, New Jersey's EDCs, including PSE&G, filed their annual joint proposal for the conduct of the February 2026 BGS auction covering energy years 2027 through 2029. The February 2025 BGS auction resulted in a significant cost increase for electricity supplied by PSE&G and all other New Jersey electric distribution companies that was reflected in customers' rates beginning June 1, 2025. The cost increases were in large part due to higher prices from the PJM capacity market (base residual auction). Rates resulting from the February 2026 BGS auction will become effective June 1, 2026.

Grid Modernization—In June 2022, following a stakeholder proceeding, the BPU Staff issued a report containing findings and recommendations to update the BPU's interconnection regulations and processes. In furtherance of the recommendations, in June 2024 the BPU amended its interconnection rules to speed up the interconnection of renewable resources to the distribution grid. Separately, in July 2024, BPU Staff convened a working group to develop recommendations for integrated distribution planning for distributed energy resources. In July 2025 and January 2026, the BPU adopted various regulations intended to streamline the process for utility interconnection applications and ensure compliance with a recently enacted law mandating that EDCs in New Jersey improve the interconnection process for certain grid supply solar and energy storage facilities. We cannot predict the impact on our business or results of operations from this Grid Modernization plan or any laws, rules or regulations promulgated as a result thereof, particularly as they may relate to PSE&G's electric distribution assets.

Cybersecurity Regulation

Federal—NERC Critical Infrastructure Protection standards establish cybersecurity and physical security protections for critical systems and facilities. These standards are also designed to promote coordination, threat sharing and interaction between utilities and various government agencies regarding potential cyber and physical threats against the nation's electric grid. The Critical Infrastructure Protection standards are designed to protect Bulk Electric System (BES) Cyber Systems that would impact the reliable operation of the BES. PSE&G is obligated to comply with the NERC Critical Infrastructure Protection standards. NERC continues to examine revising criteria for low-impact cyber systems, which could result in expanding the Critical Infrastructure Protection standards to a larger set of applicable cyber assets.

NERC Critical Infrastructure Protection standards do not apply to nuclear facilities which are instead governed by the NRC for purposes of physical and cyber security. NRC has a number of risk-informed, performance-based security programs in place to effectively protect U.S. commercial nuclear facilities. NRC has existing requirements, effective processes, and the expertise to regulate and inspect cybersecurity to ensure the federal requirements are met. NRC requires operating nuclear power plant licensees and license applicants to ensure

that digital computer and communication systems associated with a nuclear power plant's safety, security, and emergency preparedness functions are protected from cyberattacks. As a result, computer systems at operating power plants that monitor and control safety systems and help the reactor operate are isolated from external communications. Security systems that provide safeguards of the facility are also isolated from external communications, including the Internet.

NRC's Office of Nuclear Security and Incident Response established the Cyber Security Branch (CSB) to strengthen internal governance of the agency's regulatory activities. The CSB plans, coordinates, and manages agency activities related to cybersecurity for NRC applicants and licensees, such as security programs' development and policy enhancements to prevent malevolent cyber acts against NRC-licensed facilities. The CSB's cybersecurity-related responsibilities include developing rules and guidance, reviewing licensing actions, developing policy enhancements, and overseeing NRC-licensed facilities.

NRC regularly monitors the threats associated with cybersecurity, including potential threats against NRC-licensed facilities. Within the CSB there is a cyber assessment team that assesses real-world cyber events at NRC-licensed facilities. The team evaluates whether an identified threat could impact licensed facilities and makes recommendations for NRC actions and communications to the licensees. Furthermore, the NRC has established liaison relationships with the intelligence and law enforcement communities to include the National Counterterrorism Center, the U.S. Department of Homeland Security's (DHS) Computer Emergency Response Team, and the Federal Bureau of Investigation.

The Transportation Security Administration, an agency of the DHS, has issued multiple security directives since May 2021 designed to mitigate cybersecurity threats to natural gas pipelines.

State—The BPU requires utilities, including PSE&G, to, among other things, implement a cybersecurity program that defines and implements organizational accountabilities and responsibilities for cyber risk management activities, and establishes policies, plans, processes and procedures for identifying and mitigating cyber risk to critical systems. Additional requirements of this order include, but are not limited to (i) annually inventorying critical utility systems; (ii) annually assessing risks to critical utility systems; (iii) implementing controls to mitigate cyber risks to critical utility systems; (iv) monitoring log files of critical utility systems; (v) reporting cyber incidents to the BPU; and (vi) establishing a cybersecurity incident response plan and conducting biennial exercises to test the plan. In addition, New York's Stop Hacks and Improve Electronic Data Security (SHIELD) Act, which became effective in March 2020, requires businesses that own or license computerized data that includes New York State residents' private information to implement reasonable safeguards to protect that information.

ENVIRONMENTAL MATTERS

We are subject to federal, state and local laws and regulations with regard to environmental matters. Our associated obligations change as legislatures and regulators pass new laws and regulations and amend existing ones. Therefore, it is difficult to project future costs of compliance and their impact on competition. The costs of compliance associated with any new requirements that may be imposed by future regulations are not known but may be material.
For additional information related to environmental matters, including proceedings not discussed below, as well as anticipated expenditures for installation of compliance technology, hazardous substance liabilities and fuel and waste disposal costs, see Note 11. Commitments and Contingent Liabilities.

Air Pollution Control—Our facilities are subject to federal, state and local regulation that requires controls of emissions from sources of air pollution and imposes recordkeeping, reporting and permit requirements.

Hazardous Substance Liability—PSE&G's operations involve substances and byproducts classified by environmental regulations as hazardous. These regulations impose handling, storage and disposal requirements for hazardous materials. They also impose liability for damages to the environment, including cash penalties.

Site Remediation—Federal and state environmental laws and regulations require the cleanup of discharged hazardous substances. They authorize the EPA, the New Jersey Department of Environmental Protection (NJDEP) and private parties to commence lawsuits to compel clean-ups or seek reimbursement for such

remediation. The clean-ups can be more complicated and costly when the hazardous substances are in or under a body of water. Clean-up obligations may be imposed regardless of the absence of fault, contractual agreements between parties, or the legality of activities at the time of discharge.

Natural Resource Damages—Federal and state environmental laws and regulations authorize damage assessments against persons who have caused an injury to natural resources through the discharge of a hazardous substance. The NJDEP requires persons conducting remediation to address such injuries through restoration or damage assessments.

Wildlife and Habitat Protection—Federal and state environmental laws and regulations govern activities that may harm certain wildlife or habitats. These laws and regulations impose permit requirements, prohibit certain activities, and impose penalties for violations. In December 2024, the U.S. Fish and Wildlife Service proposed to designate the monarch butterfly as a “threatened” species under the federal Endangered Species Act. PSE&G is unable to determine the impact of this development.

LEGAL PROCEEDINGS

We are party to various lawsuits and environmental and regulatory matters, including in the ordinary course of business. For information regarding material legal proceedings, see Note 11. Commitments and Contingent Liabilities.

Inquiry 10: NONE

Inquiry 11: NONE

Inquiry 12: See the discussion of important regulatory and legal issues provided above.

Inquiry 13: NONE

Inquiry 14: NONE

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	47,718,418,037	45,281,389,061
3	Construction Work in Progress (107)	200-201	1,227,245,837	1,123,030,555
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		48,945,663,874	46,404,419,616
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	9,598,454,954	8,969,988,217
6	Net Utility Plant (Enter Total of line 4 less 5)		39,347,208,920	37,434,431,399
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	—	—
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		—	—
9	Nuclear Fuel Assemblies in Reactor (120.3)		—	—
10	Spent Nuclear Fuel (120.4)		—	—
11	Nuclear Fuel Under Capital Leases (120.6)		—	—
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	—	—
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		—	—
14	Net Utility Plant (Enter Total of lines 6 and 13)		39,347,208,920	37,434,431,399
15	Utility Plant Adjustments (116)		—	—
16	Gas Stored Underground - Noncurrent (117)		—	—
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		2,869,584	2,869,584
19	(Less) Accum. Prov. for Depr. and Amort. (122)		843,054	816,802
20	Investments in Associated Companies (123)		33,364,573	33,364,573
21	Investments in Subsidiary Companies (123.1)	224-225	11,277,138	11,277,138
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	—	—
24	Other Investments (124)		199,317,716	90,232,375
25	Sinking Funds (125)		—	—
26	Depreciation Fund (126)		—	—
27	Amortization Fund - Federal (127)		—	—
28	Other Special Funds (128)		38,217,766	29,902,153
29	Special Funds (Non Major Only) (129)		—	—
30	Long-Term Portion of Derivative Assets (175)		—	—
31	Long-Term Portion of Derivative Assets – Hedges (176)		—	—
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		284,203,723	166,829,021
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		—	—
35	Cash (131)		37,149,327	8,574,054
36	Special Deposits (132-134)		28,230,481	33,363,261
37	Working Fund (135)		—	—
38	Temporary Cash Investments (136)		60,000,000	70,000,000
39	Notes Receivable (141)		24,559,384	16,935,410
40	Customer Accounts Receivable (142)		1,576,541,903	1,312,158,952
41	Other Accounts Receivable (143)		65,246,841	59,833,851
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		253,746,111	214,867,745
43	Notes Receivable from Associated Companies (145)		—	—
44	Accounts Receivable from Assoc. Companies (146)		16,357,090	16,388,342
45	Fuel Stock (151)	227	—	—
46	Fuel Stock Expenses Undistributed (152)	227	—	—
47	Residuals (Elec) and Extracted Products (153)	227	—	—
48	Plant Materials and Operating Supplies (154)	227	612,882,368	641,765,439
49	Merchandise (155)	227	—	—
50	Other Materials and Supplies (156)	227	—	—
51	Nuclear Materials Held for Sale (157)	202-203/227	—	—
52	Allowances (158.1 and 158.2)	228-229	—	—

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance (d)
53	(Less) Noncurrent Portion of Allowances		—	—
54	Stores Expense Undistributed (163)	227	—	—
55	Gas Stored Underground - Current (164.1)		—	—
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		—	—
57	Prepayments (165)		16,209,629	26,715,962
58	Advances for Gas (166-167)		—	—
59	Interest and Dividends Receivable (171)		—	—
60	Rents Receivable (172)		11,895,255	9,801,802
61	Accrued Utility Revenues (173)		387,240,544	318,007,837
62	Miscellaneous Current and Accrued Assets (174)		2,370,010	3,171,590
63	Derivative Instrument Assets (175)		—	—
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		—	—
65	Derivative Instrument Assets - Hedges (176)		—	—
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		—	—
67	Total Current and Accrued Assets (Lines 34 through 66)		2,584,936,721	2,301,848,755
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		88,149,810	84,533,501
70	Extraordinary Property Losses (182.1)	230a	—	—
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	—	—
72	Other Regulatory Assets (182.3)	232	6,970,821,176	6,628,511,224
73	Prelim. Survey and Investigation Charges (Electric) (183)		42,863,043	40,643,836
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		—	—
75	Other Preliminary Survey and Investigation Charges (183.2)		2,130,395	2,680,295
76	Clearing Accounts (184)		10,729	3,269
77	Temporary Facilities (185)		—	—
78	Miscellaneous Deferred Debts (186)	233	34,536,085	36,209,018
79	Def. Losses from Disposition of Utility Plt. (187)		—	—
80	Research, Devel. and Demonstration Expend. (188)	352-353	—	—
81	Unamortized Loss on Reaquired Debt (189)		14,352,665	16,825,647
82	Accumulated Deferred Income Taxes (190)	234	802,503,638	708,027,425
83	Unrecovered Purchased Gas Costs (191)		—	—
84	Total Deferred Debits (lines 69 through 83)		7,955,367,541	7,517,434,215
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		50,171,716,905	47,420,543,390

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250-251	892,260,275	892,260,275
3	Preferred Stock Issued (204)	250-251	—	—
4	Capital Stock Subscribed (202, 205)		—	—
5	Stock Liability for Conversion (203, 206)		—	—
6	Premium on Capital Stock (207)		—	—
7	Other Paid-In Capital (208-211)	253	2,155,435,667	2,155,436,302
8	Installments Received on Capital Stock (212)	252	—	—
9	(Less) Discount on Capital Stock (213)	254	—	—
10	(Less) Capital Stock Expense (214)	254b	—	—
11	Retained Earnings (215, 215.1, 216)	118-119	16,783,813,302	15,413,607,588
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	(440,610)	(440,610)
13	(Less) Required Capital Stock (217)	250-251	—	—
14	Noncorporate Proprietorship (Non-major only) (218)		—	—
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(3,259,697)	(4,113,964)
16	Total Proprietary Capital (lines 2 through 15)		19,827,808,937	18,456,749,591
17	**LONG-TERM DEBT**			
18	Bonds (221)	256-257	16,115,000,700	15,115,000,700
19	(Less) Reacquired Bonds (222)	256-257	—	—
20	Advances from Associated Companies (223)	256-257	—	—
21	Other Long-Term Debt (224)	256-257	—	—
22	Unamortized Premium on Long-Term Debt (225)		—	—
23	(Less) Unamortized Discount on Long-Term Debt-Debt (226)		34,369,447	32,575,137
24	Total Long-Term Debt (lines 18 through 23)		16,080,631,253	15,082,425,563
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		73,361,350	82,514,233
27	Accumulated Provision for Property Insurance (228.1)		—	—
28	Accumulated Provision for Injuries and Damages (228.2)		25,194,387	22,750,017
29	Accumulated Provision for Pensions and Benefits (228.3)		308,698,301	490,028,814
30	Accumulated Miscellaneous Operating Provisions (228.4)		—	—
31	Accumulated Provision for Rate Refunds (229)		—	—
32	Long-Term Portion of Derivative Instrument Liabilities		—	—
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		—	—
34	Asset Retirement Obligations (230)		456,491,321	457,050,825
35	Total Other Noncurrent Liabilities (lines 26 through 34)		863,745,359	1,052,343,889
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		324,789,728	443,621,008
38	Accounts Payable (232)		865,753,955	704,573,024
39	Notes Payable to Associated Companies (233)		—	—
40	Accounts Payable to Associated Companies (234)		469,140,120	359,423,737
41	Customer Deposits (235)		72,046,230	68,658,533
42	Taxes Accrued (236)	262-263	4,400,082	2,597,156
43	Interest Accrued (237)		198,607,991	173,742,807
44	Dividends Declared (238)		—	—
45	Matured Long-Term Debt (239)		—	—

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance (d)
46	Matured Interest (240)		—	—
47	Tax Collections Payable (241)		629,907	144,603
48	Miscellaneous Current and Accrued Liabilities (242)		432,652,159	470,301,779
49	Obligations Under Capital Leases-Current (243)		14,973,573	15,100,665
50	Derivative Instrument Liabilities (244)		—	—
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		—	—
52	Derivative Instrument Liabilities - Hedges (245)		—	—
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		—	—
54	Total Current and Accrued Liabilities (lines 37 through 53)		2,382,993,745	2,238,163,312
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		110,802,993	70,096,290
57	Accumulated Deferred Investment Tax Credits (255)	266-267	72,995,080	84,496,232
58	Deferred Gains from Disposition of Utility Plant (256)		—	—
59	Other Deferred Credits (253)	269	246,490,130	257,608,422
60	Other Regulatory Liabilities (254)	278	2,746,650,716	3,043,997,112
61	Unamortized Gain on Reaquired Debt (257)		—	—
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	—	—
63	Accum. Deferred Income Taxes-Other Property (282)		6,413,468,227	5,976,142,501
64	Accum. Deferred Income Taxes-Other (283)		1,426,130,465	1,158,520,478
65	Total Deferred Credits (lines 56 through 64)		11,016,537,611	10,590,861,035
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		50,171,716,905	47,420,543,390

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account	(Ref.) Page No.	Total Current Year to Date Balance for Quarter/Year	Total Prior Year to Date Balance for Quarter/Year	Current 3 Months Ended Quarterly Only No 4th Quarter	Prior 3 Months Ended Quarterly Only No 4th Quarter
	(a)	(b)	(c)	(d)	(e)	(f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	9,337,312,421	8,164,444,466	—	—
3	Operating Expenses					
4	Operation Expenses (401)	320-323	5,369,718,465	4,446,074,690	—	—
5	Maintenance Expenses (402)	320-323	276,775,137	268,473,450	—	—
6	Depreciation Expense (403)	336-337	1,044,908,485	947,010,340	—	—
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	—	—	—	—
8	Amort. & Depl. of Utility Plant (404-405)	336-337	26,739,703	47,007,153	—	—
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	—	—	—	—
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		—	—	—	—
11	Amort. of Conversion Expenses (407.2)		—	—	—	—
12	Regulatory Debits (407.3)		58,017,832	45,373,361	—	—
13	(Less) Regulatory Credits (407.4)		—	—	—	—
14	Taxes Other Than Income Taxes (408.1)	262-263	64,887,615	59,946,341	—	—
15	Income Taxes - Federal (409.1)	262-263	111,403,327	(72,807,026)	—	—
16	- Other (409.1)	262-263	(7,058,725)	(2,990,114)	—	—
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	2,799,028,129	1,859,456,059	—	—
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	2,750,528,861	1,488,334,486	—	—
19	Investment Tax Credit Adj. - Net (411.4)	266	(11,501,153)	(11,447,245)	—	—
20	(Less) Gains from Disp. of Utility Plant (411.6)		—	—	—	—
21	Losses from Disp. of Utility Plant (411.7)		—	—	—	—
22	(Less) Gains from Disposition of Allowances (411.8)		—	—	—	—
23	Losses from Disposition of Allowances (411.9)		—	—	—	—
24	Accretion Expense (411.10)		—	—	—	—
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24.2)		6,982,389,954	6,097,762,523	—	—
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		2,354,922,467	2,066,681,943	—	—

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. 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 material refund to the utility with respect to power or gas purchases. State for each year effected 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 or gas purchases.
11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 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 appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars)	Previous Year to Date (in dollars)	Current Year to Date (in dollars)	Previous Year to Date (in dollars)	Current Year to Date (in dollars)	Previous Year to Date (in dollars)	Line No.
(g)	(h)	(i)	(j)	(k)	(l)	
						1
6,759,432,798	5,926,459,581	2,577,879,623	2,237,984,885		—	2
						3
3,741,695,548	3,079,825,711	1,628,022,917	1,366,248,979		—	4
228,305,933	220,306,537	48,469,204	48,166,913		—	5
787,007,076	705,913,369	257,901,409	241,096,971		—	6
	—		—		—	7
9,496,859	32,450,723	17,242,844	14,556,430		—	8
	—		—		—	9
—	—	—	—		—	10
	—		—		—	11
31,288,456	23,167,753	26,729,376	22,205,608		—	12
—	—	—	—		—	13
44,816,706	41,778,528	20,070,909	18,167,813		—	14
109,109,651	20,759,873	2,293,676	(93,566,899)		—	15
(9,404,847)	2,063,462	2,346,122	(5,053,576)		—	16
1,703,178,970	1,187,235,863	1,095,849,159	672,220,196		—	17
1,582,081,347	917,316,260	1,168,447,514	571,018,226		—	18
(10,796,154)	(10,726,977)	(704,999)	(720,268)		—	19
	—		—		—	20
	—		—		—	21
	—		—		—	22
	—		—		—	23
—	—	—	—		—	24
5,052,616,851	4,385,458,582	1,929,773,103	1,712,303,941	—	—	25
1,706,815,947	1,541,000,999	648,106,520	525,680,944	—	—	26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account	(Ref.) Page No.	Total Current Year to Date Balance for Quarter/Year	Total Prior Year to Date Balance for Quarter/Year	Current 3 Months Ended Quarterly Only No 4th Quarter	Prior 3 Months Ended Quarterly Only No 4th Quarter
	(a)	(b)	(c)	(d)	(e)	(f)
27	Net Utility Operating Income (Carried forward from page 114)		2,354,922,467	2,066,681,943	—	—
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		50,851,094	65,446,355	—	—
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		36,371,242	40,660,625	—	—
33	Revenues From Nonutility Operations (417)		—	—	—	—
34	(Less) Expenses of Nonutility Operations (417.1)		(453)	91,053	—	—
35	Nonoperating Rental Income (418)		(26,252)	(27,041)	—	—
36	Equity in Earnings of Subsidiary Companies (418.1)	119	—	—	—	—
37	Interest and Dividend Income (419)		16,459,455	14,255,989	—	—
38	Allowance for Other Funds Used During Construction (419.1)		43,687,954	41,015,095	—	—
39	Miscellaneous Nonoperating Income (421)		8,825,470	12,121,153	—	—
40	Gain on Disposition of Property (421.1)		3,782	833	—	—
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		83,430,714	92,060,706	—	—
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		—	—	—	—
44	Miscellaneous Amortization (425)		—	—	—	—
45	Donations (426.1)		2,558,873	2,412,089	—	—
46	Life Insurance (426.2)		—	—	—	—
47	Penalties (426.3)		2,834,373	942,857	—	—
48	Exp. for Certain Civic, Political & Related Activities (426.4)		9,120,542	8,785,813	—	—
49	Other Deductions (426.5)		28,702,140	6,929,761	—	—
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		43,215,928	19,070,520	—	—
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,632,541	1,305,903	—	—
53	Income Taxes-Federal (409.2)	262-263	(4,496,644)	6,515,121	—	—
54	Income Taxes-Other (409.2)	262-263	7,745,841	2,946,178	—	—
55	Provision for Deferred Inc. Taxes (410.2)	272-277	1,641,575	9	—	—
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	272-277	438,332	263,912	—	—
57	Investment Tax Credit Adj.-Net (411.5)		—	—	—	—
58	(Less) Investment Tax Credits (420)		—	—	—	—
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		6,084,981	10,503,299	—	—
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		34,129,805	62,486,887	—	—
61	Interest Charges					
62	Interest on Long-Term Debt (427)		636,871,422	566,947,811	—	—
63	Amort. of Debt Disc. and Expense (428)		10,733,817	9,784,032	—	—
64	Amortization of Loss on Reaquired Debt (428.1)		2,472,983	2,946,705	—	—
65	(Less) Amort. of Premium on Debt-Credit (429)		—	—	—	—
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		—	—	—	—
67	Interest on Debt to Assoc. Companies (430)		—	—	—	—
68	Other Interest Expense (431)		13,228,058	33,280,401	—	—
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		19,459,722	30,075,381	—	—
70	Net Interest Charges (Total of lines 62 thru 69)		643,846,558	582,883,568	—	—
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		1,745,205,714	1,546,285,262	—	—
72	Extraordinary Items					
73	Extraordinary Income (434)		—	—		—
74	(Less) Extraordinary Deductions (435)		—	—		—
75	Net Extraordinary Items (Total of line 73 less line 74)		—	—	—	—
76	Income Taxes-Federal and Other (409.3)	262-263	—	—		—
77	Extraordinary Items After Taxes (line 75 less line 76)		—	—	—	—
78	Net Income (Total of line 71 and 77)		1,745,205,714	1,546,285,262	—	—

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. 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)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. 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.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. 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.
9. 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)	Current Quarter/ Year Year to Date Balance (c)	Previous Quarter Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		15,413,607,588	14,017,322,325
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Rounding			1
5				—
6				—
7				—
8				—
9	TOTAL Credits to Retained Earnings (Acct. 439)		—	1
10				—
11				—
12				—
13				—
14				—
15	TOTAL Debits to Retained Earnings (Acct. 439)		—	—
16	Balance Transferred from Income (Account 433 less Account 418.1)		1,745,205,714	1,546,285,262
17	Appropriations of Retained Earnings (Acct. 436)			
18				—
19				—
20				—
21				—
22	Total Appropriations of Retained Earnings (Acct. 436)		—	—
23	Dividends Declared-Preferred Stock (Account 437)			
24				—
25				—
26				—
27				—
28				—
29	TOTAL Dividends Declared-Preferred Stock (Account 437)		—	—
30	Dividends Declared-Common Stock (Account 438)			
31				—
32				—
33				—
34				—
35	Common Stock Dividends Declared		(375,000,000)	(150,000,000)
36	TOTAL Dividends Declared-Common Stock (Account 438)		(375,000,000)	(150,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			—
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		16,783,813,302	15,413,607,588
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				—
40				—

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. 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)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. 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.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. 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.
9. 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)	Current Quarter/ Year Year to Date Balance (c)	Previous Quarter Year Year to Date Balance (d)
41				—
42				—
43				—
44				—
45	TOTAL Appropriated Retained Earnings (Account 215)		—	—
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			—
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		—	—
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		16,783,813,302	15,413,607,588
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		(440,610)	(440,610)
50	Equity in Earnings for Year (Credit) (Account 418.1)		—	—
51	(Less) Dividends Received (Debit)		—	—
52				
53	Balance-End of Year (Total lines 49 thru 52)		(440,610)	(440,610)

STATEMENT OF CASH FLOWS

1. Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
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 in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	1,745,205,714	1,546,285,262
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	1,071,648,188	994,017,492
5	Other Regulatory Debits and Credits	58,017,832	45,373,361
6			
7			
8	Deferred Income Taxes (Net)	49,702,511	370,857,670
9	Investment Tax Credit Adjustment (Net)	(11,501,153)	(11,447,245)
10	Net (Increase) Decrease in Receivables	(232,979,776)	(118,044,925)
11	Net (Increase) Decrease in Inventory	28,883,071	(122,698,813)
12	Net (Increase) Decrease in Allowances Inventory	—	—
13	Net Increase (Decrease) in Payables and Accrued Expenses	165,608,880	(22,138,930)
14	Net (Increase) Decrease in Other Regulatory Assets	(312,450,219)	(672,077,910)
15	Net Increase (Decrease) in Other Regulatory Liabilities	40,476,957	(21,197,711)
16	(Less) Allowance for Other Funds Used During Construction	43,687,954	41,015,095
17	(Less) Undistributed Earnings from Subsidiary Companies	—	—
18			—
19	Other Current Assets and Liabilities	(53,327,135)	(42,542,742)
20	Cost of Removal	(156,184,811)	(169,539,824)
21	Miscellaneous	27,284,060	5,019,371
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	2,376,696,165	1,740,849,961
23			
24	Cash Flows from Investment Activities:		—
25	Construction and Acquisition of Plant (including land):		—
26	Gross Additions to Utility Plant (less nuclear fuel)	(2,777,597,908)	(2,962,051,611)
27	Gross Additions to Nuclear Fuel		—
28	Gross Additions to Common Utility Plant		—
29	Gross Additions to Nonutility Plant		—
30	(Less) Allowance for Other Funds Used During Construction	(43,687,954)	(41,015,095)
31			—
32	Change in Solar Loan Investment	—	—
33	Proceeds from the Sale of Property, Plant and Equipment	—	10,000
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(2,733,909,954)	(2,921,026,516)
35			
36	Acquisition of Other Noncurrent Assets (d)		—
37	Proceeds from Disposal of Noncurrent Assets (d)		—
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	—	—
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)	(3,494,840)	(3,863,915)
45	Proceeds from Sales of Investment Securities (a)	5,398,608	5,719,223

STATEMENT OF CASH FLOWS

1. Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
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 in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased	(148,057,149)	—
47	Collections on Loans	23,636,696	22,734,226
48	Excess Cash From SREC Auction Over Accrued Solar Loan Interest		—
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: COLI	8,011,462	9,941,322
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	(2,848,415,177)	(2,886,495,660)
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	1,350,000,000	2,100,000,000
62	Preferred Stock		—
63	Common Stock		—
64			—
65			
66	Net Increase in Short-Term Debt (c)	—	19,102,682
67			—
68			—
69			—
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,350,000,000	2,119,102,682
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	(350,000,000)	(750,000,000)
74	Preferred Stock		—
75	Common Stock		—
76			—
77			
78	Net Decrease in Short-Term Debt (c)	(118,831,280)	—
79	Deferred Issuance Costs (Debt and Credit Facilities)	(15,874,435)	(24,791,960)
80	Dividends on Preferred Stock	—	—
81	Dividends on Common Stock	(375,000,000)	(150,000,000)
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	490,294,285	1,194,310,722
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	18,575,273	48,665,023
87			
88	Cash and Cash Equivalents at Beginning of Period	78,574,054	29,909,031
89			
90	Cash and Cash Equivalents at End of period	97,149,327	78,574,054

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available- for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	(3,545,873)			
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value	(568,091)			
4	Total (lines 2 and 3)	(568,091)	—	—	—
5	Balance of Account 219 at End of Preceding Quarter/Year	(4,113,964)			
6	Balance of Account 219 at Beginning of Current Year	(4,113,964)			
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value	854,267			
9	Total (lines 7 and 8)	854,267	—	—	—
10	Balance of Account 219 at End of Current Quarter/Year	(3,259,697)			

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(3,545,873)		
2					
3			(568,091)		
4	—	—	(568,091)	1,546,285,262	1,545,717,171
5			(4,113,964)		
6			(4,113,964)		
7					
8			854,267		
9	—	—	854,267	1,745,205,714	1,746,059,981
10			(3,259,697)		

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.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTES TO THE FINANCIAL STATEMENTS (Continued)

Item 1: Statements presented herein are reported in accordance with the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission (FERC). Other published financial statements of Public Service Electric and Gas Company (PSE&G) are presented on a consolidated basis as part of Public Service Enterprise Group (PSEG) in accordance with Accounting Principles Generally Accepted in the United States of America (GAAP).

PSE&G's GAAP Financial Statements are presented on a consolidated basis. However, FERC requires the Financial Statements on a corporate basis, resulting in the reporting of the Company's subsidiaries as investments rather than specific assets and liabilities.

On the GAAP balance sheet, certain accounts are presented on a net basis, whereas FERC limits the extent of netting permissible:

- GAAP nets deferred income tax assets and liabilities; FERC requires a separate deferred tax asset account (Account 190).
- GAAP classifies certain items as regulatory assets and liabilities that FERC does not. Major differences are the non-legal portion Cost of Removal (Account 108) and the Unamortized Loss on Reacquired Debt (Account 189).
- GAAP nets the regulatory assets associated with ASC 740 (FAS109). FERC requires these items be reported as regulatory assets (Account 182.3) and regulatory liabilities (Account 254).

For GAAP purposes, substantially all of the investment tax credits (ITC) on our solar investments are recorded in Account 101 and 255. The ITC's are amortized over the life of the assets under ASC 740. FERC accounting requires the deferred ITC to be recorded in Account 255 and amortized over the life of the assets.

For GAAP purposes interest associated with income tax assets/liabilities is recorded as a tax item. FERC requires the interest to be recorded as interest receivable or payable. ASC 740-10 (FIN48) requires the company to record all uncertain tax positions. FERC prohibits the recording of uncertain tax positions for temporary differences.

The following is a general summary of the adjustments needed to convert the December 31, 2025 GAAP balance sheet to the FERC basis:

NOTES TO THE FINANCIAL STATEMENTS (Continued)

	Debit	Credit
Current Assets	16,311,506	
Current Liabilities	2,904,939	
Property, Plant and Equipment		11,830,617
Non-Current Assets		7,385,828
To deconsolidate subsidiaries which are consolidated for GAAP purposes.		
Non-Current Assets	570,650,944	
Current Liabilities	483,813,627	
Accumulated Provision for Depreciation	183,822,052	
Non-Current Liabilities		700,962,549
Current Assets		537,324,074
To separately state regulatory assets and liabilities.		
Property, Plant and Equipment	21,577,057	
Accumulated Deferred Investment Tax Credits		21,577,057
To recognize deferred investment tax credits related to the Company's solar investment as ITC (reported as grants for GAAP purposes).		
Deferred Income Taxes and ITC Non-Current Assets	951,190	
Def Income Taxes and Other Non-Current Liabilities	184,932	
Current Liabilities		1,136,122
To reclassify ASC 740-10 (FIN 48) Tax Adjustments.		
Non-Current Assets	802,503,638	
Accumulated Deferred Income Taxes		802,503,638
To segregate deferred income taxes for FERC.		
Property, Plant and Equipment	36,414,117	
Retained Earnings		14,089,743
Regulatory Assets		16,814,970
Accumulated Deferred Income Taxes		5,509,404
To record regulatory assets and property, plant and equipment that are recognized for regulatory purposes		
Property Plant and Equipment	50,323,408	
Non-Current Assets		50,149,856
Retained Earnings		173,552
Reclass capitalized Cloud Computing (ASU No. 2018-15)		
Current Liabilities	875,000,000	
Long Term Debt		875,000,000
Reclass current portion of Long Term Debt.		

Retained Earnings	259,541	
Current Assets	19,382,671	
Non-Current Assets	68,767,139	
Current Liabilities	51,405,460	
Non-Current Liabilities		51,665,001
Long Term Debt		88,149,810

To record all other adjustments needed to convert the balance sheet from a GAAP to FERC basis.

NOTES TO THE FINANCIAL STATEMENTS (Continued)

The following is a general summary of the adjustments needed to convert the 2025 GAAP Income Statement to the FERC basis:

	Debit	**Credit**
Operating Revenues	221,000,000	
Non-Operating Pension and OPEB Credits (Costs)	70,000,000	
Taxes Other Than Income Taxes	65,000,000	
Other Income and Deductions	30,000,000	
Depreciation and Amortization	13,000,000	
Net Income	1,000,000	
Operating Expenses		389,000,000
Income Tax Expense		11,000,000

To record GAAP to FERC accounting reclassifications and adjustments primarily related to revenues from contracts with customers, appliance services business revenue and expense reclassifications, and the depreciation and amortization adjustments associated with FERC only regulatory assets and property plant and equipment.

Supplemental Cash Flow Information

The following table provides supplemental cash flow information for the years ended December 31, 2025 and 2024.

	For the Years Ended December 31,	
	2025	**2024**
Interest Paid, Net of Amounts Capitalized	606,100,462	523,179,725
Income Taxes Paid	7,580,595	68,445,685
Accrued Property, Plant and Equipment Expenditures	365,278,321	285,684,471

Item 2: See Item 6, Note 11. Commitments and Contingent Liabilities and Note 17: Income Taxes

Item 3: No activity.

Item 4: Not applicable, PSE&G uses the accounts as prescribed

Item 5: None. Currently PSE&G has no restrictions with respect to the payment of dividends out of retained earnings.

Item 6. Included herein are Notes to PSE&G's Financial Statements, derived from PSE&G's Consolidated Notes to the Financial Statements prepared in conjunction with the annual Form 10-K Securities and Exchange Commission (SEC) Report.

Item 7. See Notes to Financial Statements below.

Item 8. See Notes to Financial Statements below.

Item 9. See Notes to Financial Statements below.

Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies

Organization

PSE&G is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU), the Federal Energy Regulatory Commission (FERC) and other federal and New Jersey state regulators. PSE&G also invests in regulated solar generation projects and energy efficiency (EE) and related programs in New Jersey, which are regulated by the BPU.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of FERC applicable to Annual Reports on Form 1. Certain line item reclassifications have been made to prior year financial statements to conform with current year presentation. These reclassifications had no impact on PSE&G's results of operations, financial condition or cash flows.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2025 up to February 26, 2026, the date that Public Service Electric and Gas Company's Generally Accepted Accounting Principles (GAAP) financial statements were issued and has updated such evaluation for disclosure purposes through April 15, 2026. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

Significant Accounting Policies

Principles of Consolidation

PSE&G has undivided interests in certain jointly-owned facilities, and is responsible for paying its ownership share of construction costs and operating expenses. PSE&G's revenues and expenses related to these facilities are consolidated in the appropriate revenue and expense categories.

Accounting for the Effects of Regulation

In accordance with accounting guidance for rate-regulated entities, PSE&G's financial statements reflect the economic effects of regulation. PSE&G defers the recognition of costs (a Regulatory Asset) or records the recognition of obligations (a Regulatory Liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PSE&G has deferred certain costs and recoveries, which are being amortized over various future periods. To the extent that collection of any such costs or payment of liabilities becomes no longer probable as a result of changes in regulation, the associated Regulatory Asset or Liability is charged or credited to income. Management believes that PSE&G's Transmission and Distribution businesses continue to meet the accounting requirements for rate-regulated entities. For additional information, see Note 4. Regulatory Assets and Liabilities.

Derivative Instruments

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchases and normal sales (NPNS), cash flow hedge and fair value hedge accounting.

Determining whether a contract qualifies as a derivative requires that management exercise significant judgment, including assessing the contract's market liquidity. PSE&G has determined that contracts to purchase and sell certain products do not meet the definition of a derivative under the current authoritative guidance since they do not provide for net settlement, or the markets are not sufficiently liquid to conclude that physical forward contracts are readily convertible to cash. Certain other contracts have been designated as NPNS and qualify for a scope exception under derivative accounting guidance.

PSE&G has a full-requirements contract with PSEG Power, an affiliate of PSE&G, to meet the gas supply requirements of PSE&G's gas customers. PSEG Power uses derivatives to hedge a portion of these anticipated BGSS obligations with PSE&G as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff.

For additional information regarding derivative financial instruments, see Note 14. Financial Risk Management Activities.

Revenue Recognition

PSE&G's regulated electric and gas revenues are recorded primarily based on services rendered to customers. PSE&G records unbilled revenues for the estimated amount customers will be billed for services rendered from the time meters were last read and billed to the end of the respective accounting period. The unbilled revenue is estimated each month based on usage per day, the number of unbilled days in the period, estimated seasonal loads based upon the time of year and the variance of actual degree-days and temperature-humidity-index hours of the unbilled period from expected norms.

Regulated revenues from the transmission of electricity are recognized as services are provided based on a FERC-approved annual formula rate mechanism. This mechanism provides for an annual filing of estimated revenue requirement with rates effective January 1 of each year. After completion of the annual period ending December 31, PSE&G files a true-up whereby it compares its actual revenue requirement to the original estimate to determine any over or under collection of revenue. PSE&G records the estimated financial statement impact of the difference between the actual and the filed revenue requirement as a refund or deferral for future recovery when such amounts are probable and can be reasonably estimated in accordance with accounting guidance for rate-regulated entities.

For additional information regarding Revenues, see Note 2. Revenues.

Depreciation and Amortization

PSE&G calculates depreciation under the straight-line method based on estimated average remaining lives of the several classes of property. These estimates are reviewed on a periodic basis and necessary adjustments are made as approved by the BPU or FERC.

	2025 Avg. Rate	2024 Avg. Rate
Electric Transmission	2.12 %	2.09 %
Electric Distribution	2.54 %	2.51 %
Gas Distribution	1.84 %	1.84 %

Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the cost of debt and equity funds used to finance the construction of new utility assets at PSE&G. The amount of AFUDC capitalized as Property, Plant and Equipment is included as a reduction of interest charges or other income for the equity portion. The amount of, and average rate used to calculate AFUDC for the year ended December 31, 2025 was $62 million and 6.64%, respectively. For the year ended December 31, 2024 the amount of, and average rate used to calculate AFUDC was $62 million and 6.43%, respectively.

Income Taxes

PSE&G files a consolidated federal income tax return with its parent company PSEG. PSEG and PSE&G file state income tax returns, some of which are combined or unitary. Income taxes are allocated to PSEG's subsidiaries in accordance with a tax allocation agreement whereby PSE&G's current and deferred tax expense is computed on a stand-alone basis. PSE&G is allocated an amount of tax similar to that which would be paid if it filed a separate income tax return, except for certain tax attributes. Allocations between PSEG and its subsidiaries are recorded through intercompany accounts. Investment tax credits (ITC) deferred in prior years are being amortized over the useful lives of the related property.

Uncertain income tax positions are accounted for using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold.

Impairment of Long-Lived Assets

Management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate, counterparty credit worthiness or market conditions, including prolonged periods of adverse commodity and capacity prices or a current expectation that a long-lived asset will be sold or disposed of significantly before the end of its previously estimated useful life, could potentially indicate an asset's or asset group's carrying amount may not be recoverable. In such an event, an undiscounted cash flow analysis is performed to determine if an impairment exists. When a long-lived asset's or asset group's carrying amount exceeds the associated undiscounted estimated future cash flows, the asset/asset group is considered impaired to the extent that its fair value is less than its carrying amount. An impairment would result in a reduction of the value of the long-lived asset/asset group through a non-cash charge to earnings. There were no impairments recorded for the year ended December 31, 2025.

Accounts Receivable—Allowance for Credit Losses

PSE&G's accounts receivable, including unbilled revenues, are primarily comprised of utility customer receivables for the provision of electric and gas service and appliance services, and are reported in the balance sheet as gross outstanding amounts adjusted for an allowance for credit losses. The allowance for credit losses reflects PSE&G's best estimate of losses on the account balances. The allowance is based on PSE&G's projection of accounts receivable aging, historical experience, economic factors and other currently available evidence. PSE&G's electric bad debt expense is recovered through the Societal Benefits Clause (SBC) mechanism. See Note 2. Revenues and Note 4. Regulatory Assets and Liabilities.

Accounts receivable are charged off in the period in which the receivable is deemed uncollectible. Recoveries of accounts receivable are recorded when it is known they will be received.

Materials and Supplies and Fuel

PSE&G's materials and supplies are carried at average cost and charged to inventory when purchased and expensed or capitalized to Property, Plant and Equipment, as appropriate, when installed or used.

Property, Plant and Equipment

PSE&G's additions to and replacements of existing property, plant and equipment are capitalized at cost. The cost of maintenance, repair and replacement of minor items of property is charged to expense as incurred. At the time units of depreciable property are retired or otherwise disposed of, the original cost, adjusted for net salvage value, is charged to accumulated depreciation.

Leases

PSE&G, when acting as lessee or lessor, determines if an arrangement is a lease at inception. PSE&G assesses contracts to determine if the arrangement conveys (i) the right to control the use of the identified property, (ii) the right to obtain substantially all of the economic benefits from the use of the property, and (iii) the right to direct the use of the property.

Lessee—Operating Lease Right-of-Use Assets represent the right to use an underlying asset for the lease term and Operating Lease Liabilities represent the obligation to make lease payments arising from the lease. Operating Lease Right-of-Use Assets and Operating Lease Liabilities are recognized at the lease commencement date based on the present value of lease payments over the lease term.

The current portion of Operating Lease Liabilities is included in Other Current Liabilities. Operating Lease Right-of-Use Assets and noncurrent Operating Lease Liabilities are included as separate captions in Noncurrent Assets and Noncurrent Liabilities, respectively, on the Balance Sheets of PSE&G. PSE&G does not recognize Operating Lease Right-of-Use Assets and Operating Lease Liabilities for leases where the term is twelve months or less.

PSE&G recognizes the lease payments on a straight-line basis over the term of the leases and variable lease payments in the period in which the obligations for those payments are incurred.

As lessee, most of the operating leases of PSE&G do not provide an implicit rate; therefore, incremental borrowing rates are used based on the information available at commencement date in determining the present value of lease payments. The implicit rate is used when readily determinable. PSE&G's incremental borrowing rates are based on secured borrowing rates.

Lease terms may include options to extend or terminate the lease when it is reasonably certain that such options will be exercised.

PSE&G has lease agreements with lease and non-lease components. For real estate, equipment and vehicle leases, the lease and non-lease components are accounted for as a single lease component.

Trust Investments

These securities comprise amounts that are deposited to fund a Rabbi Trust which was established to meet the obligations related to non-qualified pension plans and deferred compensation plans. Unrealized gains and losses on equity security investments are recorded in Net Income. The debt securities are classified as available-for-sale with the unrealized gains and losses recorded as a component of Accumulated Other Comprehensive Income (Loss). Realized gains and losses on both equity and available-for-sale debt security investments are recorded in earnings and are included with the unrealized gains and losses on equity securities in Net Gains (Losses) on Trust Investments. If applicable, other-than-temporary impairments on Rabbi Trust debt securities are also included in Net Gains (Losses) on Trust Investments. See Note 8. Trust Investments for further discussion.

Pension and Other Postretirement Benefits (OPEB) Plans

The market-related value of plan assets held for the qualified pension and OPEB plans is equal to the fair value of those assets as of year-end. Fair value is determined using quoted market prices and independent pricing

services based upon the security type as reported by the trustee at the measurement date (December 31) as well as investments in unlisted real estate which are valued via third-party appraisals.

See Note 10. Pension, Other Postretirement Benefits (OPEB) and Savings Plans for further discussion.

Use of Estimates

The preparation of financial statements in conformity with GAAP and FERC 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.

Recent Accounting Standards

Improvements to Income Tax Disclosures—ASU 2023-09

This ASU makes amendments to the current reconciliation disclosure to improve transparency by requiring consistent categories and greater jurisdictional disaggregation. The ASU also provides for the inclusion of an income taxes paid disclosure by jurisdiction. The ASU is effective for annual periods beginning after December 15, 2024. PSE&G adopted this standard on December 31, 2025 without a material impact on its financial statements.

Note 2. Revenues

Contract Balances

PSE&G did not have any material contract balances (rights to consideration for services already provided or obligations to provide services in the future for consideration already received) as of December 31, 2025 and 2024. Substantially all of PSE&G's accounts receivable and unbilled revenues result from contracts with customers that are priced at tariff rates. The allowance for credit losses represented approximately 12% and 13% of accounts receivable (including unbilled revenues) as of December 31, 2025 and 2024, respectively.

Accounts Receivable—Allowance for Credit Losses

PSE&G's accounts receivable, including unbilled revenues, is primarily comprised of utility customer receivables for the provision of electric and gas service and appliance services, and are reported on the balance sheet as gross outstanding amounts adjusted for an allowance for credit losses. The allowance for credit losses reflects PSE&G's best estimate of losses on the account balances. The allowance is based on PSE&G's projection of accounts receivable aging, historical experience, economic factors and other currently available evidence. PSE&G's electric bad debt expense is recoverable through its Societal Benefits Clause (SBC) mechanism.

The following provides a reconciliation of PSE&G's allowance for credit losses for the years ended December 31, 2025 and 2024.

	Year Ended December 31, 2025
	Millions
Balance as of January 1, 2025	$ 215
Utility Customer and Other Accounts	
Provision	145
Write-offs, net of Recoveries of $42 million	(106)
Balance as of December 31, 2025	$ 254

	Year Ended December 31, 2024
	Millions
Balance as of January 1, 2024	$ 283
Utility Customer and Other Accounts	
Provision	103
Write-offs, net of Recoveries of $31 million	(171)
Balance as of December 31, 2024	$ 215

Note 3. Property, Plant and Equipment and Jointly-Owned Facilities

Information related to Property, Plant and Equipment as of December 31, 2025 and 2024 is detailed below:

	As of December 31, 2025	As of December 31, 2024
	Millions	
Electric Transmission	$ 18,701	$ 17,874
Electric Distribution	13,717	12,520
Gas Distribution and Transmission	13,350	12,536
Construction Work in Progress	1,233	1,132
Other	1,751	2,136
Total	**$ 48,752**	**$ 46,198**

PSE&G has ownership interests in and is responsible for providing its respective share of the necessary financing for the following jointly-owned facilities to which it is a party. All amounts reflect PSE&G's share of the jointly-owned projects and the corresponding direct expenses are included in the Statements of Operations as Operating Expenses.

		As of December 31,			
		2025		2024	
	Ownership Interest	Plant	Accumulated Depreciation	Plant	Accumulated Depreciation
		Millions			
Transmission Facilities	Various	$ 163	$ 75	$ 164	$ 72

Note 4. Regulatory Assets and Liabilities

PSE&G prepares its financial statements in accordance with GAAP for regulated utilities as described in Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies. PSE&G has deferred certain costs based on rate orders issued by the BPU or FERC or based on PSE&G's experience with prior rate proceedings. Most of PSE&G's Regulatory Assets and Liabilities as of December 31, 2025 are supported by written orders, either explicitly or implicitly through the BPU's treatment of various cost items. These costs will be recovered and amortized over various future periods.

Regulatory Assets and other investments and costs incurred under our various infrastructure filings and clause mechanisms are subject to prudence reviews and can be disallowed in the future by regulatory authorities. To the extent that collection of any infrastructure or clause mechanism revenue, Regulatory Assets or payments of Regulatory Liabilities is no longer probable, the amounts would be charged or credited to income.

PSE&G had the following Regulatory Assets and Liabilities as recorded in accordance with GAAP:

	As of December 31,	
	2025	**2024**
	Millions	
Regulatory Assets		
Deferred Income Tax Regulatory Assets	$ 2,273	$ 2,012
Green Program Recovery Charges (GPRC)	1,593	1,251
Pension and OPEB Costs	1,213	1,330
Asset Retirement Obligations (ARO)	237	221
Clean Energy Future-Energy Cloud (CEF-EC)	206	233
Cost of Removal	184	195
Societal Benefits Clause (SBC)	182	211
Manufactured Gas Plant (MGP) Remediation Costs	179	210
New Jersey Clean Energy Program	145	145
Conservation Incentive Program (CIP)	127	261
COVID-19 Deferral	109	131
Remediation Adjustment Charge (RAC) (Other SBC)	101	102
Clean Energy Future-Electric Vehicles (CEF-EV)	92	51
2024 Distribution Base Rate Case Regulatory Assets (BRC)	85	108
Other	242	180
Total Regulatory Assets	**$ 6,968**	**$ 6,641**
Less: Current Regulatory Assets	537	516
Total Noncurrent Regulatory Assets	**$ 6,431**	**$ 6,125**

	As of December 31, 2025	2024
	Millions	
Regulatory Liabilities		
Deferred Income Tax Regulatory Liabilities	$ 2,317	$ 2,619
Gas Costs-Basic Gas Supply Service (BGSS)	118	145
Other	97	62
Total Regulatory Liabilities	**$ 2,532**	**$ 2,826**
Less: Current Regulatory Liabilities	484	555
Total Noncurrent Regulatory Liabilities	**$ 2,048**	**$ 2,271**

All Regulatory Assets and Liabilities are excluded from PSE&G's rate base unless otherwise noted. The Regulatory Assets and Liabilities in the table above are defined as follows:

- **ARO:** These costs represent the differences between rate-regulated cost of removal accounting and asset retirement accounting under GAAP. These costs will be recovered in future rates as assets are retired.

- **BRC:** Represents deferred costs, primarily comprised of storm costs incurred in the cleanup of major storms, approved for a five-year recovery pursuant to the 2024 Distribution Base Rate Case Settlement.

- **CEF-EC (AMI Meter Deployment):** In October 2024, the BPU approved recovery of PSE&G's CEF-EC capital and operating costs associated with its electric smart meter deployment program. Included in the approved recovery was the return on and of the capital investments in AMI meters and infrastructure, incremental operating costs of the program and stranded costs associated with the accelerated retirement of the non-AMI electric meters.

- **CIP:** The CIP reduces the impact on electric and gas distribution revenues from changes in sales volumes and demand for most customers. The CIP provides for a true-up of current period revenue as compared to revenue established in PSE&G's most recent distribution base rate proceeding. Recovery under the CIP is subject to certain limitations, including an actual versus allowed return on equity test and ceilings on customer rate increases.

- **CEF-EV (Electric Vehicles):** In October 2024, the BPU approved recovery of PSE&G's CEF-EV capital and operating costs associated with its electric vehicle program, which provides incentives to customers related to EV charger installations. Included in the approved recovery was the return on and of PSE&G's capital investments and customer incentives, and recovery of incremental operating costs of the program, incurred through November 2024. The BPU also approved annual filings for recovery of future EV investments and costs associated with the program.

- **Cost of Removal:** PSE&G accrues and collects in rates for the cost of removing, dismantling and disposing of its electric distribution, electric transmission and gas distribution upon retirement. The Regulatory Asset or Liability for non-legally required cost of removal represents the difference between amounts collected in rates and costs actually incurred.

- **COVID-19 Deferral:** These amounts represent incremental costs related to COVID-19 as approved for recovery by the BPU over a five-year period starting June 1, 2025.

- **Deferred Income Tax Regulatory Assets:** These amounts relate to deferred income taxes arising from utility operations that have not been included in customer rates relating to depreciation, ITCs and other flowthrough items, including the accumulated deferred income taxes related to tax repair and mixed service cost deductions.

  As part of PSE&G's 2018 distribution base rate case settlement with the BPU and the establishment of the TAC mechanism, PSE&G agreed to a ten-year flowback to customers of its accumulated deferred income taxes from previously realized tax repair deductions which resulted in the recognition of a $581 million Regulatory Asset and Regulatory Liability as of September 30, 2018. In addition, PSE&G agreed to the current flowback of tax benefits from ongoing tax repair deductions which results in the recording of a Regulatory Asset upon flowback each year.

  As part of PSE&G's 2024 base rate case settlement with the BPU, PSE&G agreed to an additional five-year flowback to customers of its accumulated deferred income taxes from previously realized mixed service cost deductions which resulted in the recognition of a $509 million Regulatory Asset and Regulatory Liability as of September 30, 2024. In addition, PSE&G agreed to the current flowback of tax benefits from ongoing mixed service cost deductions which results in the recording of a Regulatory Asset upon flowback each year.

  For the years ended December 31, 2025, 2024 and 2023, PSE&G had provided $58 million, $81 million and $80 million, respectively, in current tax repair flowbacks to customers. The flowback of current mixed service costs commenced in January 2025 and was $22 million for the year ended December 31, 2025. The recovery and amortization of the tax repair and mixed service cost-related Deferred Income Tax Regulatory Assets is being recovered through the TAC regulatory mechanism.

- **Deferred Income Tax Regulatory Liabilities:** These liabilities primarily relate to amounts due to customers for excess deferred income taxes as a result of the reduction in the federal corporate income tax rate provided in the Tax Cuts and Jobs Act of 2017, and accumulated deferred income taxes from previously realized distribution-related tax repair and mixed service cost deductions. As part of its settlement with its regulators, PSE&G agreed to refund the excess deferred income taxes as follows:

  - Protected distribution-related excess deferred income taxes are being refunded to customers over the
    remaining useful lives of distribution property, plant and equipment through PSE&G's TAC mechanism. As of December 31, 2025, the balance remaining to be flowed back to customers was approximately $808 million.

  - Previously realized distribution-related tax repair deductions are being refunded to customers over ten years through PSE&G's TAC mechanism. As of December 31, 2025, the balance remaining to be flowed back to customers was approximately $232 million through 2028.

  - Previously realized distribution-related mixed service cost deductions are being refunded to customers over five years through PSE&G's TAC mechanism. As of December 31, 2025, the balance to be flowed back to customers was approximately $266 million through 2029.

  - Protected transmission-related excess deferred income taxes are being refunded to customers over the remaining useful life of transmission property, plant and equipment through PSE&G's transmission formula rate mechanism. As of December 31, 2025, the balance remaining to be flowed back to customers was approximately $926 million.

- **Gas Costs—BGSS:** These costs represent the over or under recovered amounts associated with BGSS, pursuant to processes approved by the BPU. Pursuant to BPU requirements, PSE&G serves as the supplier of last resort for gas customers within its service territory that are not served by another supplier. Pricing for those services are set by the BPU as a pass-through, resulting in no

margin for PSE&G's operations. Over or under collected balances are returned or recovered through an annual filing. Interest is accrued only on over recovered balances.

- **GPRC:** PSE&G files an annual GPRC petition with the BPU for recovery of amounts associated with the BPU Board-approved energy efficiency (EE) and solar (renewable) energy (RE) programs that include a return on and of investments and capital assets, as well as recovery for deferred expenses and incremental costs. The GPRC investment program component is recovered over the lives of the underlying investments and capital assets which range from five to twenty years.

  The approved GPRC components receiving recovery for the return on and of investments include: Carbon Abatement, Energy Efficiency Economic Stimulus Program (EEE), EEE Extension Program, EEE Extension II Program, Solar Generation Investment Program (Solar 4 All®), Solar 4 All® Extension, Solar 4 All® Extension II, Solar Loan II Program, Solar Loan III Program, EE 2017 Program, Clean Energy Future–Energy Efficiency (CEF-EE) and CEF-EE-II.

  In addition, the GPRC components receiving cost recovery for deferred expenses include: the Transition Renewable Energy Certificate Program, Community Solar Energy Program and the Successor Solar Incentive Program.

  The Regulatory Asset balances represent the deferred investment and related undercollected balances with a Regulatory Liability recorded for any overrecovered balance. Interest is accrued monthly on any over-or under- recovered balances. Amortization of deferred investment and expenses are recorded in O&M expense. The capital asset portion of GPRC investments primarily in company-owned solar facilities is included in Property, Plant and Equipment, with depreciation recorded in Depreciation and Amortization Expense.

- **MGP Remediation Costs:** Represents the low end of the range for the remaining environmental investigation and remediation program cleanup costs for MGPs that are probable of recovery in future rates. Once these costs are incurred, they are recovered through the RAC in the SBC over a seven year period with interest.

- **New Jersey Clean Energy Program:** The BPU approved future funding requirements for EE and RE Programs. The BPU funding requirements are recovered through the SBC.

- **Pension and OPEB Costs:** PSE&G records the unrecognized costs for defined benefit pension and other OPEB plans on the balance sheet as Regulatory Assets pursuant to the adoption of accounting guidance for employers' defined benefit pension and OPEB plans, and relevant BPU orders. These costs represent net actuarial gains or losses and prior service costs which have not been expensed. These costs are amortized and recovered in future rates.

- **RAC (Other SBC):** Costs incurred to clean up MGPs which are recovered over seven years with interest through an annual filing.

- **SBC:** The SBC, as authorized by the BPU and the New Jersey Electric Discount and Energy Competition Act, includes costs related to PSE&G's electric and gas business as follows: (1) the Universal Service Fund; (2) EE & RE Programs; (3) Electric bad debt expense; and (4) the RAC for incurred MGP remediation expenditures. Over or under recovered balances with interest are to be returned or recovered through an annual filing.

Significant 2025 regulatory orders received and currently pending rate filings with the BPU or FERC by PSE&G are as follows:

- **BGSS—**In April 2025, the BPU gave final approval to PSE&G's BGSS rate of approximately 33 cents per therm, which was effective on October 1, 2024.

In May 2025, PSE&G made its annual filing with the BPU requesting an increase to its BGSS rate to approximately 36 cents per therm, effective October 1, 2025. This matter is pending.

Under BGSS Orders issued by the BPU, New Jersey gas distribution companies (GDCs) may self-implement a rate increase resulting in no more than a 5% bill increase effective December 1 of the current year, and February 1 of the following year, with one month's advance notice to the BPU and New Jersey Rate Counsel, and implement a decrease in its BGSS rate at any time during the year upon five days' notice to the BPU and New Jersey Rate Counsel. On December 1, 2025, in compliance with the BGSS Orders, PSE&G self-implemented a BGSS increase from approximately 33 cents per therm to approximately 36 cents per therm, resulting in an approximate 3% bill increase.

- **Clean Energy Future-Electric Vehicles (CEF-EV)—**In January 2026, PSE&G filed an updated cost recovery petition to recover $8 million annually in electric base rates effective April 1, 2026. This filing requests the return on and of investment for CEF-EV electric investments placed in service through December 31, 2025. This matter is pending.

- **CIP—**In February 2025, the BPU gave final approval to provisional electric CIP rates which were effective August 1, 2024.

  In May 2025, the BPU gave final approval to the provisional gas CIP rates which were effective October 1, 2024.

  In December 2025, the BPU approved on a provisional basis, PSE&G's annual gas CIP petition recover deficient gas revenues of approximately $97 million effective January 1, 2026, based on the 12-month period ending September 2025.

  In January 2026, the BPU gave final approval to the provisional electric CIP rates recovering annual deficient electric revenues of approximately $65 million. The provisional rate was effective June 1, 2025.

  In March 2026, PSE&G filed its annual electric CIP petition seeking BPU approval to return to customers excess revenues of approximately $26 million based on the 12-month period ending May 31, 2026 with new rates proposed to be effective June 1, 2026. This matter is pending.

- **Electric Generation/Capacity Cost Deferral (EGCCD)—**In June 2025, the BPU approved an Order authorizing PSE&G to provide a $30 credit to each residential electric customer's monthly bill for the two-month period July through August 2025. For the six-month period September 2025 through February 2026, PSE&G is applying a charge to each residential electric customer's monthly bill of $10. Similar orders were issued to all other New Jersey Electric Distribution Companies (EDCs) and were as a result of state regulators' concern about electric bill increases this summer, which the BPU attributed to the increasing demand for power and a lack of sufficient new generation resources, which led to significant price increases in the 2025/2026 PJM capacity auction.

- **Gas System Modernization Program II Extension (GSMP II Ext)—**In July 2025, the BPU approved PSE&G's updated GSMP II Ext petition to recover $49 million annually in gas base rates effective August 1, 2025. The approved gas revenue increase represents the return on and of actual GSMP II Ext investments placed in service through April 30, 2025.

  In February 2026, PSE&G filed a GSMP II Ext. cost recovery petition seeking BPU approval to recover in gas rates an annual revenue increase of $4 million effective September 1, 2026 to recover the return on and of investment in GSMP II Ext gas investments to be placed in service through May 31, 2026. This matter is pending.

In March 2026, the BPU approved PSE&G's updated GSMP II Ext cost recovery petition to recover $23 million annually in gas base rates effective April 1, 2026. The approved gas revenue increase represents the return on and of actual GSMP II Ext investments placed in service through October 31, 2025.

- **Green Program Recovery Charges (GPRC)—**In May 2025, the BPU approved PSE&G's updated 2024 cost recovery petition for annual electric and gas revenue increases of $54 million and $22 million, respectively.

  In June 2025, PSE&G filed its 2025 GPRC cost recovery petition requesting BPU approval for recovery of increases of $207 million and $24 million in annual electric and gas revenues, respectively. This matter is pending.

- **Infrastructure Advancement Program (IAP)—**In April 2025, the BPU approved PSE&G's updated cost recovery petition to recover in electric and gas base rates an annual revenue increase of approximately $6 million and $3 million, respectively, effective May 1, 2025. This increase represents the return of and on investment for IAP electric investments in service through January 31, 2025.

  In January 2026, PSE&G filed an updated IAP cost recovery petition seeking BPU approval to recover in electric and gas base rates annual revenue increases of $10 million and $4 million, respectively. This increase represents the return of and on IAP investments in service through December 31, 2025. This matter is pending.

- **RAC—**In January 2025, the BPU approved PSE&G's RAC 30 petition approving recovery of approximately $56 million of net MGP expenditures incurred from August 1, 2021 through July 31, 2022, with new rates effective February 15, 2025.

- **Tax Adjustment Credit (TAC)—**In October 2025, PSE&G submitted its annual 2025 TAC filing requesting a reduction to the tax benefits being flowed back to customers, which would result in an increase to annual electric and gas revenues by approximately $15 million and $10 million, respectively. This matter is pending.

- **Transmission Formula Rates—**In June 2025, in accordance with its transmission formula protocols, PSE&G filed with the FERC its 2024 true-up adjustment relating to its transmission formula rates in effect for calendar year 2024. The June 2025 true-up filing resulted in an approximate $28 million increase in the 2024 revenue requirement from the revenue requirement amount contained in the forecast filing. PSE&G previously recognized the majority of the increased revenue in 2024.

  In October 2025, PSE&G filed its annual transmission formula rate update with FERC, which will result in an approximate $82 million increase in its annual transmission revenue effective January 1, 2026, subject to true-up.

- **ZEC Program**—In August 2025, the BPU approved the final ZEC price of $10 per MWh for the Energy Year ended May 31, 2025. As a result, PSE&G purchased approximately $164 million of ZECs including interest, from the eligible nuclear plants selected by the BPU with the final payment made in August 2025. As a result of the collections and required ZEC payments, there were overcollected revenues totaling $5.5 million, including interest. In January 2026, the BPU directed PSE&G to eliminate its ZEC tariff rate, effective February 1, 2026 and for PSE&G to apply the overcollected ZEC revenue balance into the USF component of PSE&G's SBC clause.

Note 5. Leases

Lessee

PSE&G has operating leases for office space for customer service centers, rooftops and land for its Solar 4 All® facilities, equipment, vehicles and land for certain electric substations. These leases have remaining lease terms through 2044, some of which include options to extend the leases for up to four 5-year terms or one 10-year term; and two include options to extend the leases for one 45-year and one 48-year term, respectively. Some leases have fixed rent payments that have escalations based on certain indices, such as the CPI. Certain leases contain variable payments.

Operating Lease Costs

The following amounts relate to total operating lease costs, including both amounts recognized in the Statements of Operations during the years ended December 31, 2025 and 2024 and any amounts capitalized as part of the cost of another asset, and the cash flows arising from lease transactions.

	Year Ended December 31, 2025	Year Ended December 31, 2024
	Millions	
Operating Lease Costs		
Long-term Lease Costs	$ 48	$ 43
Short-term Lease Costs	17	21
Variable Lease Costs	2	2
Total Operating Lease Costs	**$ 67**	**$ 66**
Cash Paid for Amounts Included in the Measurement of Operating Lease Liabilities	$ 19	$ 20
Weighted Average Remaining Lease Term in Years	8	9
Weighted Average Discount Rate	4.0 %	4.0 %

Operating lease liabilities as of December 31, 2025 had the following maturities on an undiscounted basis:

	Millions
2026	$ 18
2027	15
2028	11
2029	10
2030	10
Thereafter	39
Total Minimum Lease Payments	**$ 103**

The following is a reconciliation of the undiscounted cash flows to the discounted Operating Lease Liabilities recognized on the Balance Sheets:

	As of December 31, 2025	2024
	Millions	
Undiscounted Cash Flows	$ 103	$ 116
Reconciling Amount due to Discount Rate	(16)	(18)
Total Discounted Operating Lease Liabilities	**$ 87**	**$ 98**

As of December 31, 2025 and 2024, the current portions of Operating Lease Liabilities included in Other Current Liabilities was $14 million and $15 million, respectively.

Note 6. Long-Term Investments

Long-Term Investments as of December 31, 2025 and 2024 included the following:

	As of December 31, 2025	2024
	Millions	
CEF-EE II On-Bill Repayment (OBR) Program (A)	$ 131	$ —
Life Insurance and Supplemental Benefits	59	67
Solar Loans	9	23
Total Long-Term Investments	**$ 199**	**$ 90**

(A) As part of the CEF–EE II OBR program, PSE&G provides funding to customers to upgrade equipment to increase energy efficiency. See Note 7. Financing Receivables for more information on the OBR program.

Note 7. Financing Receivables

OBR Program

As part of the CEF–EE II OBR program that began in 2025, PSE&G provides funding to customers to upgrade equipment to increase energy efficiency. The OBR program allows customers to repay their portion of costs for equipment upgrades over time directly through their PSE&G bill. The terms of these agreements can be five, seven or ten years. Customers must meet acceptable credit standards to participate in the program. As of December 31, 2025, there have been no defaults under the OBR program; however, in the event a default, amounts would be recovered through a regulatory recovery mechanism. Therefore, no current credit losses have been recorded for the OBR program. A substantial portion of these amounts are noncurrent and reported in Long-Term Investments on PSE&G's Balance Sheets. The following table reflects the outstanding amounts by class of customer.

Outstanding OBR Loans by Class of Customers

	As of December 31, 2025 Millions
Commercial/Industrial	$ 17
Residential	128
Total	$ 145
Current Portion (included in Accounts Receivable)	(14)
Noncurrent Portion (included in Long-Term Investments)	**$ 131**

Payments on all outstanding loans were current as of December 31, 2025 and have an average remaining life of approximately 7 years.

Solar Loan Program

PSE&G's Solar Loan Programs are designed to help finance the installation of solar power systems throughout its electric service area. Interest income on the loans is recorded on an accrual basis. The loans are paid back with SRECs generated from the related installed solar electric system. PSE&G uses collection experience as a credit quality indicator for its Solar Loan Programs and conducted a comprehensive credit review for all borrowers. As of December 31, 2025, none of the solar loans were impaired; however, in the event a loan becomes impaired, the basis of the solar loan would be recovered through a regulatory recovery mechanism. Therefore, no current credit losses have been recorded for Solar Loan Programs I, II and III. The following table reflects the outstanding loans by class of customer, none of which would be considered "non-performing."

Outstanding Solar Loans by Class of Customers

	As of December 31,	
	2025	**2024**
	Millions	
Commercial/Industrial	$ 19	$ 38
Residential	1	2
Total	$ 20	$ 40
Current Portion (included in Accounts Receivable)	(11)	(17)
Noncurrent Portion (included in Long-Term Investments)	**$ 9**	**$ 23**

The solar loans originated under three Solar Loan Programs are comprised as follows:

Programs	Balance as of December 31, 2025	Funding Provided	Residential Loan Term	Non-Residential Loan Term
	Millions			
Solar Loan II	$ 9	prior to 2015	10 years	15 years
Solar Loan III	11	prior to 2022	10 years	10 years
Total	**$ 20**			

The average life of loans paid in full is 8 years, which is lower than the loan terms of 10 to 15 years due to the generation of SRECs being greater than expected and/or cash payments made to the loan. Payments on all outstanding loans were current as of December 31, 2025 and have an average remaining life of approximately 2 years. There are no remaining residential loans outstanding under the Solar Loan I and II programs.

Note 8. Trust Investments

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a “Rabbi Trust.”

The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for PSE&G’s allocated portion of the securities held in the Rabbi Trust.

	As of December 31, 2025			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Domestic Equity Securities	$ 1	$ 2	$ —	$ 3
Available-for-Sale Debt Securities				
Government	$ 18	$ —	$ (3)	$ 15
Corporate	12	—	(1)	11
Total Available-for-Sale Debt Securities	$ 30	$ —	$ (4)	$ 26
Total Rabbi Trust Investments	**$ 31**	**$ 2**	**$ (4)**	**$ 29**

	As of December 31, 2024			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Domestic Equity Securities	$ 1	$ 2	$ —	$ 3
Available-for-Sale Debt Securities				
Government	$ 19	$ —	$ (4)	$ 15
Corporate	14	—	(2)	12
Total Available-for-Sale Debt Securities	$ 33	$ —	$ (6)	$ 27
Total Rabbi Trust Investments	**$ 34**	**$ 2**	**$ (6)**	**$ 30**

The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less and greater than 12 months.

	As of December 31, 2025				As of December 31, 2024			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Available-for-Sale Debt Securities								
Government (A)	$ —	$ —	$ 12	$ (3)	$ 2	$ —	$ 13	$ (4)
Corporate (B)	1	—	7	(1)	2	—	9	(2)
Total Available-for-Sale Debt Securities	$ 1	$ —	$ 19	$ (4)	$ 4	$ —	$ 22	$ (6)
Rabbi Trust Investments	**$ 1**	**$ —**	**$ 19**	**$ (4)**	**$ 4**	**$ —**	**$ 22**	**$ (6)**

(A) Debt Securities (Government)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). The unrealized losses on PSE&G's Rabbi Trust investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. PSE&G also has investments in municipal bonds. It is not expected that these securities will settle for less than their amortized cost. PSE&G does not intend to sell these securities nor will it be more-likely-than-not required to sell before recovery of their amortized cost. PSE&G did not recognize credit losses for U.S. Treasury obligations and Federal Agency mortgage-backed securities because these investments are guaranteed by the U.S. government or an agency of the U.S. government. PSE&G did not recognize credit losses for municipal bonds because they are primarily investment grade securities.

(B) Debt Securities (Corporate)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). Unrealized losses were due to market declines. It is not expected that these securities would settle for less than their amortized cost. PSE&G does not intend to sell these securities nor will it be more-likely-than-not required to sell before recovery of their amortized cost. PSE&G did not recognize credit losses for corporate bonds because they are primarily investment grade.

The proceeds from the sales of and the net gains (losses) on securities in the Rabbi Trust Fund were:

	Year Ended December 31, 2025	Year Ended December 31, 2024
Proceeds from Rabbi Trust Sales (A)	**$ 5**	**$ 6**
Net Realized Gains (Losses):		
Gross Realized Gains	$ —	$ —
Gross Realized Losses	—	—
Net Realized Gains (Losses) on Rabbi Trust	**$ —**	**$ —**
Unrealized Gains (Losses) on Equity Securities in Rabbi Trust	—	—
Net Gains (Losses) on Rabbi Trust Investments	**$ —**	**$ —**

(A) The cost of these securities was determined on the basis of specific identification.

The Rabbi Trust debt securities held as of December 31, 2025 had the following maturities:

Time Frame	Fair Value Millions
Less than one year	$ 1
1 - 5 years	5
6 - 10 years	3
11 - 15 years	2
16 - 20 years	3
Over 20 years	12
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 26**

PSE&G periodically assesses individual debt securities whose fair value is less than amortized cost to determine whether the investments are considered to be impaired. For these securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). Any subsequent recoveries of the noncredit loss component of the impairment would be recorded through Accumulated Other Comprehensive Income (Loss). Any subsequent recoveries of the credit loss component would be recognized through earnings. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Note 9. Asset Retirement Obligations (AROs)

PSE&G recognizes liabilities for the expected cost of retiring long-lived assets for which a legal obligation exists to remove or dispose of an asset or some component of an asset at retirement. These AROs are recorded at fair value in the period in which they are incurred and are capitalized as part of the carrying amount of the related long-lived assets. PSE&G, as a rate-regulated entity, recognizes Regulatory Assets or Liabilities as a result of timing differences between the recording of costs and costs recovered through the rate-making process.

PSE&G has conditional AROs primarily for legal obligations related to the removal of treated wood poles and the requirement to seal natural gas pipelines at all sources of gas when the pipelines are no longer in service. PSE&G does not record an ARO for its protected steel and poly-based natural gas lines, as management believes that these categories of gas lines have an indeterminable life.

For PSE&G, Regulatory Assets and Regulatory Liabilities result when accretion and amortization are adjusted to match rates established by regulators resulting in the regulatory deferral of any gain or loss.

The changes to the ARO liabilities for PSE&G during 2025 and 2024 are presented in the following table:

	2025	2024
	Millions	
ARO Liability as of January 1,	$ 457	$ 401
Liabilities Settled	(10)	(12)
Accretion Expense Deferred and Recovered in Rate Base (A)	20	16
Revision to Present Values of Estimated Cash Flows	(10)	52
ARO Liability as of December 31,	**$ 457**	**$ 457**

(A) Not reflected as expense in Statements of Operations.

In 2024, PSE&G recorded an increase to its ARO liabilities primarily due to the impact of increases in labor rates and other costs, partially offset by decreases from changes in inflation and discount rate assumptions. Those changes had no impact on PSE&G's Statement of Operations.

Note 10. Pension, Other Postretirement Benefits (OPEB) and Savings Plans

PSEG sponsors and Services administers qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. PSEG merged its two qualified defined benefit pension plans (Pension Plan of Public Service Enterprise Group Incorporated and Pension Plan of Public Service Enterprise Group Incorporated II, or the Plans) effective January 1, 2026. The merged qualified pension plan includes a Final Average Pay and two Cash Balance components and both represented and non-represented employees are eligible for participation.

PSE&G is required to record the under or over funded positions of their defined benefit pension and OPEB plans on its balance sheets. Such funding positions are required to be measured as of the date of its year-end Balance Sheets. For underfunded plans, the liability is equal to the difference between the plan's benefit obligation and the fair value of plan assets. For defined benefit pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. In addition, GAAP requires that the total unrecognized costs for defined benefit pension and OPEB plans be recorded as an after-tax charge to Accumulated Other Comprehensive Income (Loss), a separate component of Stockholders' Equity. However, for PSE&G, because the amortization of the unrecognized costs is being collected from

customers, the accumulated unrecognized costs are recorded as a Regulatory Asset. The unrecognized costs represent actuarial gains or losses and prior service costs which have not been expensed. The charge to Accumulated Other Comprehensive Income (Loss) and the Regulatory Asset for PSE&G are amortized and recorded as net periodic pension cost in the Statements of Operations.

Pension and OPEB (credits) costs for PSE&G are detailed as follows:

	Pensions Benefits Years Ended December 31,		Other Benefits Years Ended December 31,	
	2025	2024	2025	2024
		Millions		
Total Benefit Costs (Credits)	$ 47	$ 43	$ (4)	$ (2)

Plan Assets

The investments of pension and OPEB plans are held in trust accounts by the Trustee and consist of an undivided interest in an investment account of the Master Retirement Trust. The investments in the pension and OPEB plans are measured at fair value within a hierarchy that prioritizes the inputs to fair value measurements into three levels. See Note 15. Fair Value Measurements for more information on fair value guidance. Use of the Master Trust permits the commingling of pension plan assets and OPEB plan assets for investment and administrative purposes. Although assets of the plans are commingled in the Master Trust, the Trustee maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the respective participating plans. The net investment income of the investment assets is allocated by the Trustee to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating plans. Additional investments of OPEB plans included in the Fair Value of Assets are held in a Welfare Trust. As of December 31, 2025, the pension plan interest and OPEB plan interest in such assets were approximately 91% and 9%, respectively.

401(k) Plans

PSEG sponsors two 401(k) plans, which are defined contribution retirement plans subject to the Employee Retirement Income Security Act (ERISA). Eligible represented employees of PSEG's subsidiaries participate in the PSEG Employee Savings Plan (Savings Plan), while eligible non-represented employees of PSEG's subsidiaries participate in the PSEG Thrift and Tax-Deferred Savings Plan (Thrift Plan). Eligible employees may contribute up to 50% of their annual eligible compensation to these plans, not to exceed the IRS maximums, including any catch-up contributions for those employees age 50 and above. PSEG matches 50% of such employee contributions up to 7% of pay for Savings Plan participants and up to 8% of pay for Thrift Plan participants.

Employees hired or rehired on or after January 1, 2025 can choose between two different Retirement Program options - the "Core Contribution / 401(k) Program" or the "Cash Balance / 401(k) Program." The Cash Balance / 401(k) Program provides pay credits in the Cash Balance components of PSEG's qualified pension plans and a 401(k) company match of employee contributions as noted above. The Core Contribution / 401(k) Program provides participants with a non-elective Core Contribution equal to 4% of their eligible earnings in the 401(k) Plan, as well as a dollar-for-dollar company match of up to 4% each pay period. Active participants in the Cash Balance components of PSEG's qualified pension plans as of December 31, 2024 were also given a one-time election period to choose between the two Retirement Programs above. Elections to switch to the Core Contribution / 401(k) Program were effective January 1, 2026.

In addition to the above, beginning January 1, 2025, employees who are not participants in the Final Average Pay Component of PSEG's qualified pension plans may also be eligible for an annual company contribution to the 401(k) Plan.

The amounts expensed for employer contributions to the above plans for PSE&G is detailed as follows:

	Thrift Plan and Savings Plan Years Ended December 31,	
	2025	**2024**
	Millions	
PSE&G Matching Contributions	**$ 35**	**$ 31**

Note 11. Commitments and Contingent Liabilities

Environmental Matters

Newark Bay Complex

The Newark Bay Complex is a tidal estuary in northern New Jersey that includes Newark Bay, as well as portions of the Passaic River, the Hackensack River and other surrounding waterways. The U.S. Environmental Protection Agency (EPA) has designated various portions of the Newark Bay Complex as federal Superfund sites that must be investigated and remediated under the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA).

Lower Passaic River Study Area

The EPA has determined that a 17-mile stretch of the Passaic River (Lower Passaic River Study Area (LPRSA)) in New Jersey is a “Superfund” site. PSE&G and certain of its predecessors conducted operations at properties in this area, including at one site that was transferred to PSEG Power.

The EPA has announced two separate cleanup plans for the Lower 8.3 miles and Upper 9 miles of the LPRSA. The EPA’s plan for the Lower 8.3 miles involves dredging and capping sediments at an estimated cost of $2.3 billion, and its plan for the Upper 9 miles involves dredging and capping sediments at an estimated cost of $550 million. Additional cleanup work may be required depending on the results of these initial phases of work. Occidental Chemical Corporation (Occidental) has voluntarily completed the design of the cleanup plan for the Lower 8.3 miles and has received an EPA Unilateral Administrative Order directing it to design the cleanup plan for the Upper 9 miles.

Occidental has filed two lawsuits against PSE&G and others to attempt to recover costs associated with its past investigation and cleanup work within the LPRSA and to obtain a declaratory judgment of parties’ shares of any future costs. PSEG cannot predict the outcome of the litigation.

In January 2026, Occidental’s parent company completed the sale of Occidental to a third party and identified a new company, Environmental Resource Holdings, LLC, as the successor to Occidental’s environmental liability at the Newark Bay Complex and elsewhere. PSE&G and others have filed suit for a declaratory judgment that Occidental remains liable for investigation and cleanup costs within the Newark Bay Complex and elsewhere.

The EPA finalized and received court approval of a settlement with 82 parties who have agreed to pay $150 million to resolve their LPRSA CERCLA liability, in whole or in part. This settlement is being appealed. PSE&G is not included in the settlement, but the EPA sent PSE&G, Occidental, and several other Potentially Responsible Parties (PRPs) a letter in March 2022 inviting them to submit to the EPA individually or jointly an offer to fund or participate in the next stages of the remediation. PSEG submitted a good faith offer to the EPA in June 2022 on behalf of PSE&G. PSEG understands that the EPA is evaluating its offer.

As of December 31, 2025, PSE&G has an Environmental Costs Liability of $53 million and a corresponding Regulatory Asset based on its continued ability to recover such costs in its rates.

The outcome of this matter is uncertain, and until (i) a final remedy for the entire LPRSA is selected and an agreement is reached by the PRPs to fund it, (ii) PSE&G’s share of the costs are determined, and (iii) PSE&G’s ability to recover the costs in its rates is determined, it is not possible to predict this matter’s ultimate impact on PSE&G’s financial statements. It is possible that PSE&G will record additional costs beyond what it has accrued, and that such costs could be material, but PSE&G cannot at the current time estimate the amount or range of any additional costs.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which is an extension of the LPRSA and includes Newark Bay and portions of surrounding waterways. The EPA has notified PSEG and 21 other PRPs of their potential liability. PSE&G is unable to estimate its portion of any loss or possible range of loss related to this matter.

Natural Resource Damage Claims

New Jersey and certain federal regulators have alleged that PSE&G and 56 other PRPs may be liable for natural resource damages within the LPRSA. In particular, PSE&G and other PRPs received notice from federal regulators of the regulators' intent to move forward with a series of studies assessing potential damages to natural resources at the Diamond Alkali Superfund site, which includes the LPRSA and the Newark Bay Study Area. PSE&G is unable to estimate its portion of any possible loss or range of loss related to this matter.

Hackensack River

EPA has designated approximately 23 river miles of the Lower Hackensack River as a federal Superfund site. The site runs from the river's confluence with Newark Bay north to the Oradell Dam. PSE&G and certain of its predecessors conducted operations at properties in this area, including at the Hudson, Bergen and Kearny generating stations that were transferred to PSEG Power.

In 2024, the EPA identified PSE&G and four other parties as PRPs for the site and requested that they voluntarily perform a technical study of a portion of the Lower Hackensack River designated as "Operable Unit 2." PSE&G has agreed to participate in the technical study. PSE&G does not believe participation in the technical study will have a material impact on its results of operations and financial condition; however, future costs related to this matter could be material.

In September 2025, the EPA identified PSE&G and three other parties as PRPs for a new portion of the Lower Hackensack River. EPA requested the PRPs voluntarily perform a technical study for this incremental portion designated as "Operable Unit 3." PSE&G is considering the EPA's request. PSE&G cannot predict the outcome of this matter.

MGP Remediation Program

PSE&G is working with the New Jersey Department of Environmental Protection (NJDEP) to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $179 million and $196 million on an undiscounted basis, including its $53 million share for the Passaic River as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $179 million as of December 31, 2025. Of this amount, $23 million was recorded in Other Current Liabilities and $156 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $179 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly. PSE&G completed sampling in the Passaic River in 2020 to delineate coal tar from certain MGP sites that abut the Passaic River Superfund site. PSEG cannot determine at this time the magnitude of any impact on the Passaic River Superfund remedy.

Basic Generation Service (BGS), Basic Gas Supply Service (BGSS) and Zero Emission Certificates (ZECs)

Each year, PSE&G obtains its electric supply requirements through annual New Jersey BGS auctions for two categories of customers that choose not to purchase electric supply from third-party suppliers. The first category is residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category is larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Energy Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreements with the winners of these RSCP and CIEP BGS auctions to purchase BGS for PSE&G's load

requirements. The winners of the RSCP and CIEP auctions are responsible for fulfilling all the requirements of a PJM load-serving entity including the provision of capacity, energy, ancillary services and any other services required by PJM. As such, prices set through these auctions are impacted by FERC-approved prices set in the PJM capacity auctions, which significantly increased for the 2025/2026 and subsequent auction years. See Note 2. Revenues for additional information. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2026 is $677.73 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2026 of $696.05 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2023	**2024**	**2025**	**2026**	
36- Month Terms Ending	May 2026	May 2027	May 2028	May 2029	**(A)**
Load (MW)	2,800	2,900	2,800	2,800	
$ per MWh	$93.11	$80.88	$107.36	$109.38	

(A) Prices set in the 2026 BGS auction will become effective on June 1, 2026 when the 2023 BGS auction agreements expire.

PSE&G has a full-requirements contract with PSEG Power to meet the gas supply requirements of PSE&G's gas customers. PSEG Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for PSEG Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 18. Related-Party Transactions.

Pursuant to a process established by the BPU, New Jersey EDCs, including PSE&G, were required to purchase ZECs from eligible nuclear plants selected by the BPU. In April 2021, PSEG Power's Salem 1, Salem 2 and Hope Creek nuclear plants were awarded ZECs for the three-year eligibility period from June 2022 through May 2025. PSE&G purchased the ZECs on a monthly basis with payment to be made annually following completion of each energy year. The ZEC program ended effective June 1, 2025, and the final ZEC payment from PSE&G to PSEG Power settled in August 2025.

FERC Matters

FERC has completed a non-public investigation of the Roseland-Pleasant Valley (RPV) transmission project. In December 2024, FERC approved an agreement between PSE&G and FERC Enforcement Staff resolving its investigation. The agreement included a $6.6 million civil penalty and the implementation of certain compliance requirements, in addition to the process improvements that PSE&G has already implemented. It also included a statement that nothing in the agreement reflected a challenge by FERC Enforcement to the end-of-life determination relative to the project and that no disgorgement had been sought. In both a December 2024 proceeding related to PJM's annual cost allocation filing and in PSE&G's 2025 annual formula rate true-up filing, an intervenor raised an objection related to the recovery of costs for the RPV project. FERC rejected the first challenge as procedurally out of scope and has not acted on, and does not need to act on, the second filing. In

January 2026, that same intervenor filed a FERC complaint against PSE&G requesting that FERC set a hearing on the recovery of these costs. PSE&G has sought dismissal of the complaint but cannot predict the outcome of this matter.

BPU Audit of PSE&G

In 2020, the BPU ordered the commencement of a comprehensive affiliate and management audit of PSE&G. It has been more than ten years since the BPU last conducted a management and affiliate audit of this kind of PSE&G, which is initiated periodically as required by New Jersey statutes/regulations. Phase 1 of the audit reviews affiliate relations and cost allocation between PSE&G and its affiliates, including an analysis of the relationship between PSE&G and PSEG Energy Resources & Trade, LLC, a wholly owned subsidiary of PSEG Power over the past ten years, and between PSE&G and PSEG Long Island. Phase 2 is a comprehensive management audit, which addresses, among other things, executive management, corporate governance, system operations, human resources, cyber security, compliance with customer protection requirements and customer safety. The audit officially began in late May 2021. The BPU Audit Staff submitted the final audit report to the BPU in June 2023. The BPU is currently considering public comments on the audit report and has not yet determined which audit recommendations it will require PSE&G to implement. It is not possible at this time to predict the outcome of this matter.

Other Litigation and Legal Proceedings

PSE&G is party to various lawsuits in the ordinary course of business. In view of the inherent difficulty in predicting the outcome of such matters, PSE&G generally cannot predict the eventual outcome of the pending matters, the timing of the ultimate resolution of these matters, or the eventual loss, fines or penalties related to each pending matter.

In accordance with applicable accounting guidance, a liability is accrued when those matters present loss contingencies that are both probable and reasonably estimable. In such cases, there may be an exposure to loss in excess of any amounts accrued. PSE&G will continue to monitor the matter for further developments that could affect the amount of the accrued liability that has been previously established.

Based on current knowledge, management does not believe that loss contingencies arising from pending matters, other than the matters described herein, could have a material adverse effect on PSE&G's financial position or liquidity. However, in light of the inherent uncertainties involved in these matters, some of which are beyond PSE&G's control, and the large or indeterminate damages sought in some of these matters, an adverse outcome in one or more of these matters could be material to PSE&G's results of operations or liquidity for any particular reporting period.

Note 12. Debt and Credit Facilities

Long-Term Debt

	Maturity	As of December 31, 2025	2024
		Millions	
First and Refunding Mortgage Bonds (A):			
	2037	$ 7	$ 7
8.00%	2037	8	8
5.00%		15	15
Total First and Refunding Mortgage Bonds			
Medium-Term Notes (MTNs) (A):			
3.00%	2025	—	350
0.95%	2026	450	450
2.25%	2026	425	425
3.00%	2027	425	425
3.70%	2028	375	375
3.65%	2028	325	325
3.20%	2029	375	375
2.45%	2030	300	300
1.90%	2031	425	425
3.10%	2032	500	500
4.90%	2032	400	400
4.65%	2033	500	500
5.20%	2033	500	500
5.20%	2034	450	450
4.85%	2034	600	600
5.05%	2035	400	—
5.25%	2035	250	250
4.90%	2035	450	—
5.70%	2036	250	250
5.80%	2037	350	350
5.38%	2039	250	250
5.50%	2040	300	300
3.95%	2042	450	450
3.65%	2042	350	350
3.80%	2043	400	400
4.00%	2044	250	250
4.05%	2045	250	250
4.15%	2045	250	250
3.80%	2046	550	550

3.60%	2047	350	350
4.05%	2048	325	325
3.85%	2049	375	375
3.20%	2049	400	400
3.15%	2050	300	300
2.70%	2050	375	375
2.05%	2050	375	375
3.00%	2051	450	450
5.13%	2053	400	400
5.45%	2053	400	400
5.45%	2054	550	550
5.30%	2054	500	500
5.50%	2055	500	—
Total MTNs		16,100	15,100
Principal Amount Outstanding		16,115	15,115
Amounts Due Within One Year		(875)	(350)
Net Unamortized Discount and Selling Expense		(123)	(117)
Total Long-Term Debt of PSE&G		**$ 15,117**	**$ 14,648**

(A) Secured by essentially all property of PSE&G pursuant to its First and Refunding Mortgage.

Long-Term Debt Maturities

The aggregate principal amounts of maturities for each of the five years following December 31, 2025 are as follows:

Year	Millions
2026	$ 875
2027	425
2028	700
2029	375
2030	300
Thereafter	13,440
Total	**$ 16,115**

Long-Term Debt Financing Transactions

During 2025, the following long-term debt transactions occurred:

- issued $400 million of 5.05% Secured Medium-Term Notes, Series Q, due March 2035,
- issued $500 million of 5.50% Secured Medium-Term Notes, Series Q, due March 2055,
- issued $450 million of 4.90% Secured Medium-Term Notes, Series Q, due August 2035, and
- retired $350 million of 3.00% Secured Medium-Term Notes, Series K, at maturity.

In January 2026, PSE&G issued $500 million of 4.20% Secured Medium-Term Notes, Series R, due January 2031 and $500 million of 5.63% Secured Medium-Term Notes, Series R, due January 2056.

In March 2026, PSE&G retired $450 million of 0.95% Secured Medium-Term Notes, Series N, at maturity.

Short-Term Liquidity

PSE&G maintains a commercial paper program to meet its short-term liquidity requirements. The commercial paper program is fully back-stopped by its credit facility.

The commitments under the $1.0 billion credit facility are provided by a diverse bank group. As of December 31, 2025, the total available credit capacity was $649 million.

As of December 31, 2025, no single institution represented more than 7% of the total commitments in the credit facilities.

As of December 31, 2025, PSE&G's liquidity position, including credit facilities and access to external financing, was expected to be sufficient to meet its projected stressed requirements over a 12-month planning horizon.

The credit facility is restricted as to availability and use as listed below.

	As of December 31, 2025				
Company/Facility	**Total Facility**	**Usage (A)**	**Available Liquidity**	**Expiration Date**	**Primary Purpose**
	Millions				
Revolving Credit Facility	$ 1,000	$ 351	$ 649	Mar 2029	Commercial Paper Support/Funding/Letters of Credit
Total	**$ 1,000**	**$ 351**	**$ 649**		

(A) The primary use PSE&G's credit facility is to support its Commercial Paper Program, under which as of December 31, 2025, PSE&G had $325 million Commercial Paper outstanding at a weighted average interest rate of 3.89%.

In March 2026, PSE&G executed a two-year extension to its existing $1 billion revolving credit facility, extending the maturity through March 2031.

Fair Value of Debt

The estimated fair values, carrying amounts and methods used to determine the fair values of long-term debt as of December 31, 2025 and 2024 are included in the following table and accompanying notes as of December 31, 2025 and 2024. See Note 15. Fair Value Measurements for more information on fair value guidance and the hierarchy that prioritizes the inputs to fair value measurements into three levels.

	December 31, 2025		December 31, 2024	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt (A)	**$ 15,992**	**$ 14,705**	**$ 14,998**	**$ 13,337**

(A) Given that these bonds do not trade actively, the fair value amounts of taxable debt securities (primarily Level 2 measurements) are generally determined by a valuation model using market-based measurements that are processed through a rules-based pricing methodology. The fair value amounts above do not represent the price at which the outstanding debt may be called for redemption by the issuer under the debt agreements.

Note 13. Schedule of Consolidated Capital Stock

As of December 31, 2025, PSE&G had an aggregate of 7.5 million shares of $100 par value and 10 million shares of $25 par value Cumulative Preferred Stock, which were authorized and unissued and which, upon issuance, may or may not provide for mandatory sinking fund redemption.

Note 14. Financial Risk Management Activities

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchases and normal sales (NPNS), cash flow hedge and fair value hedge accounting. PSE&G uses interest rate swaps and other derivatives, which are designated and qualifying as cash flow or fair value hedges

Interest Rates

PSE&G is subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment.

Commodity Credit Risk

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guarantee or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2025, PSE&G held parental guarantees, letters of credit and cash as security. PSE&G's BGS suppliers' credit exposure is calculated each business day. As of December 31, 2025, PSE&G had $6 million in unsecured mark-to-market credit exposure with its suppliers.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

Note 15. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSE&G has the ability to access. These consist primarily of listed equity securities and money market mutual funds, as well as natural gas contracts executed on an exchange.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts, all option contracts and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement.

Certain derivative transactions may transfer from Level 2 to Level 3 if inputs become unobservable and internal modeling techniques are employed to determine fair value. Conversely, measurements may transfer from Level 3 to Level 2 if the inputs become observable. There were no transfers in 2025 and 2024 to or from Level 3.

The following tables present information about PSE&G's assets and (liabilities) measured at fair value on a recurring basis as of December 31, 2025 and December 31, 2024, including the fair value measurements and the levels of inputs used in determining those fair values.

		Recurring Fair Value Measurements as of 12/31/2025			
Description:	**Total**	**Netting**	**Quoted Market Prices for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Assets:			Millions		
Cash Equivalents (A)	$ 60	$ —	$ 60	$ —	$ —
Rabbi Trust: (B)					
Equity Securities	$ 3	$ —	$ 3	$ —	$ —
Debt Securities—U.S. Treasury	$ 10	$ —	$ —	$ 10	$ —
Debt Securities—Govt Other	$ 5	$ —	$ —	$ 5	$ —
Debt Securities—Corporate	$ 11	$ —	$ —	$ 11	$ —

Description:	Total	Netting	Recurring Fair Value Measurements as of 12/31/2024 Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:		Millions			
Cash Equivalents (A)	$ 70	$ —	$ 70	$ —	$ —
Rabbi Trust: (B)					
Equity Securities	$ 3	$ —	$ 3	$ —	$ —
Debt Securities—U.S. Treasury	$ 10	$ —	$ —	$ 10	$ —
Debt Securities—Govt Other	$ 5	$ —	$ —	$ 5	$ —
Debt Securities—Corporate	$ 12	$ —	$ —	$ 12	$ —

(A) Represents money market mutual funds.

(B) The Rabbi Trust maintains investments in a Russell 3000 index fund and various fixed income securities. These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities). For additional information, see Note 8. Trust Investments.

Level 1—Certain other equity securities in the Rabbi Trust Fund consists primarily of investments in money market funds which seek a high level of current income as is consistent with the preservation of capital and the maintenance of liquidity. To pursue its goals, the funds normally invest in diversified portfolios of high quality, short-term, dollar-denominated debt securities and government securities. The funds' net asset value is priced and published daily. The Rabbi Trust's Russell 3000 index fund is valued based on quoted prices in an active market and can be redeemed daily without restriction.

Level 2—Rabbi Trust fixed income securities include investment grade corporate bonds, collateralized mortgage obligations, asset-backed securities and certain government and U.S. Treasury obligations or Federal Agency asset-backed securities and municipal bonds with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

Note 16. Net Other Income (Deductions)

	Years Ended December 31, 2025	2024
	Millions	
Net Other Income (Deductions)		
Allowance for Funds Used During Construction	$ 44	$ 41
Solar Loan Interest	3	5
Other Interest	13	9
Other	4	9
Total Net Other Income (Deductions)	**$ 64**	**$ 64**

Note 17. Income Taxes

The components of PSE&G's income tax provision are as follows:

	For the Years Ended December 31,	
	2025	**2024**
	Millions	
Income Taxes:		
Current Expense (Benefit):		
Federal	$ 115	$ (67)
State	1	—
Total Current	116	(67)
Deferred Expense (Benefit):		
Federal	(125)	209
State	167	162
Total Deferred	42	371
Investment Tax Credit Benefit	(6)	(6)
Total Income Tax Expense (Benefit)	**$ 152**	**$ 298**

A reconciliation of reported income tax expense for PSE&G with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 21% is as follows:

	For the Years Ended December 31,			
	2025		**2024**	
	Millions	%	Millions	%
Pre-Tax Income	$ 1,897		$ 1,845	
U.S. Federal Statutory Tax Rate	399	21.0 %	387	21.0 %
State and Local Income Taxes, Net of Federal Income Tax Effect (a)	133	7.0 %	128	6.9 %
Tax Credits	(9)	(0.5)%	(9)	(0.5)%
Nontaxable or Nondeductible Items	3	0.2 %	2	0.1 %
Changes in Unrecognized Tax Benefits	2	0.1 %	—	—
Effect of Utility Ratemaking				
Tax Adjustment Credit	(313)	(16.5)%	(145)	(7.9)%
GPRC-CEF-EE	(75)	(3.9)%	(52)	(2.8)%
Other Flow-Through Accounting	10	0.5 %	(9)	(0.5)%
Other Adjustments	2	0.1 %	(4)	(0.2)%
Effective Tax Rate	**$ 152**	8.0 %	**$ 298**	16.2 %

(a) State Taxes in New Jersey made up the majority (greater than 50%) of the tax effect in this category.

	As of December 31, 2025	2024
	Millions	
Deferred Income Taxes		
Assets:		
Regulatory Liability Excess Deferred Tax	$ 365	$ 314
OPEB	16	22
Bad Debt	52	43
Operating Leases	19	20
Customer Advances	23	15
Other	46	39
Total Assets	$ 521	$ 453
Liabilities:		
Plant-Related Items	$ 4,923	$ 4,631
New Jersey Corporate Business Tax	1,421	1,303
Pension Costs	200	199
Taxes Recoverable Through Future Rates (net)	486	250
GPRC-CEF-EE	291	214
Conservation Costs	91	103
Operating Leases	18	20
Other	114	152
Total Liabilities	$ 7,544	$ 6,872
Summary of Accumulated Deferred Income Taxes:		
Net Deferred Income Tax Liabilities	$ 7,023	$ 6,419
ITC	51	58
Net Total Deferred Income Taxes and ITC	**$ 7,074**	**$ 6,477**

The deferred tax effect of certain assets and liabilities is presented in the table above net of the deferred tax effect associated with the respective regulatory deferrals.

PSE&G provides deferred taxes at the enacted statutory tax rate for all temporary differences between the financial statement carrying amounts and the tax bases of assets and liabilities irrespective of the treatment for ratemaking purposes. Management believes that it is probable that the accumulated tax benefits that previously have been treated as a flow-through item to PSE&G customers will be recovered from or refunded to PSE&G's customers in the future. See Note 4. Regulatory Assets and Liabilities.

The 2018 decrease in the federal tax rate resulted in PSE&G recording excess deferred income taxes. As of December 31, 2025, the remaining balance of excess deferred income taxes is all protected and was approximately $1.2 billion with a Regulatory Liability of approximately $1.7 billion. In 2025, PSE&G returned approximately $436 million of excess deferred income taxes and previously realized and current period deferred income taxes related to tax repair deductions to its customers with a reduction to tax expense of approximately $313 million. The flowback to customers of the excess deferred income taxes and previously realized tax repair deductions resulted in a decrease of approximately $355 million in the Regulatory Liability. The current period tax repair deduction reduces tax expense and revenue and recognizes a Regulatory Asset as PSE&G believes it is probable that the current

period tax repair deductions flowed through to the customers will be recovered from customers in the future. See Note 4. Regulatory Assets and Liabilities for additional information.

In August 2022, the Inflation Reduction Act (IRA) was signed into law. The IRA enacted a 15% corporate alternative minimum tax (CAMT), which is based on adjusted financial statement income (AFSI), effective in 2023, and made certain changes to existing energy tax credit laws.

In 2025, PSE&G determined that it is subject to CAMT as it is an applicable corporation in accordance with the statute. The impact of the CAMT for the twelve months ended December 31, 2025 was not material. PSE&G had determined that it is not subject to the CAMT for 2024 and 2023 as it was not an applicable corporation in accordance with the statute. In February 2026, Treasury issued Notice 2026-07 (CAMT Notice) which clarifies AFSI computation by allowing an adjustment to deduct certain repair and maintenance costs that are capitalized in the applicable financial statement. This CAMT Notice will result in a reduction to AFSI for CAMT purposes. However, certain CAMT rules remain unclear; therefore, the issuance of future authoritative guidance could materially impact PSE&G's results of operations, financial condition and cash flows.

In April 2023, the U.S. Treasury issued Revenue Procedure 2023-15 that provides a Natural Gas Safe Harbor (NGSH) method of accounting to determine the annual repair tax deduction for gas T&D property. As a result of the CAMT Notice, PSE&G intends to adopt the NGSH method for its gas distribution assets in its 2025 Federal tax return including a historical cumulative IRC Section 481(a) adjustment. While PSE&G is still evaluating this guidance, it expects that the additional repair deductions will reduce our taxable income and AFSI, and will result in lower cash taxes.

Despite the issuance of proposed regulations and various Notices that provide interim guidance on numerous provisions of the IRA, many aspects of the IRA, including the CAMT, remain unclear and are in need of further guidance; therefore, the impact of several provisions of the IRA will have on PSE&G's financial statements is subject to continued evaluation.

In July 2025, "An Act to Provide for Reconciliation Pursuant to Title II of H. Con. Res. 14" (the Act) was signed into law. The impact of the Act on PSE&G's financial statements is subject to continued evaluation.

As of December 31, 2025, PSE&G had a $120 million New Jersey Corporate Business Tax NOL that is expected to be fully realized in the future.

PSE&G recorded the following amounts related to its unrecognized tax benefits:

	2025	2024
	Millions	
Total Amount of Unrecognized Tax Benefits as of January 1,	$ 8	$ 11
Increases as a Result of Positions Taken in a Prior Period	11	—
Decreases as a Result of Positions Taken in a Prior Period	—	(3)
Increases as a Result of Positions Taken during the Current Period	—	1
Decreases as a Result of Positions Taken during the Current Period	—	—
Decreases as a Result of Settlements with Taxing Authorities	—	—
Decreases due to Lapses of Applicable Statute of Limitations	—	(1)
Total Amount of Unrecognized Tax Benefits as of December 31,	$ 19	$ 8
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(14)	(5)
Regulatory Asset—Unrecognized Tax Benefits	(1)	(1)
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 4**	**$ 2**

PSE&G includes accrued interest and penalties related to uncertain tax positions required to be recorded as Income Tax Expense in the Statements of Income. Accumulated interest and penalties that are recorded on the Balance Sheets on uncertain tax positions were as follows:

	As of December 31,	
	2025	2024
	Millions	
Accumulated Interest and Penalties on Uncertain Tax Positions	**$ 1**	**$ —**

A description of income tax years that remain subject to examination by material jurisdictions, where an examination has not already concluded are:

United States	
Federal	N/A
New Jersey	2015-2018
New Jersey	2021-2024

Note 18. Related-Party Transactions

The financial statements for PSE&G include transactions with related parties presented as follows:

	As of December 31,	
Related Party Transactions	**2025**	**2024**
	Millions	
Billings from Affiliates:		
Net Billings from PSEG Power (A)	$ 1,106	$ 959
Administrative Billings from Services (B)	545	516
Total Billings from Affiliates	**$ 1,651**	**$ 1,475**

Related Party Transactions	**Years Ended December 31, 2025**	**2024**
	Millions	
Payable to PSEG Power (A)	$ 228	$ 209
Payable to Services (B)	102	116
Payable to PSEG (C)	142	37
Accounts Payable—Affiliated Companies	**$ 472**	**$ 362**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable (Receivable) (C)	**$ 7**	**$ (2)**

(A) PSE&G has entered into a requirements contract with PSEG Power under which PSEG Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. In addition, PSEG Power sold ZECs to PSE&G from its nuclear units under the ZEC program as approved by the BPU. The rates in the BGSS contract and for the ZEC sales were prescribed by the BPU. BGSS sales were billed and settled on a monthly basis. ZEC sales were billed on a monthly basis and settled annually following completion of each energy year. The ZEC program ended effective June 1, 2025, with the final ZEC payment from PSE&G to PSEG Power settled in August 2025. In addition, PSEG Power and PSE&G provide certain technical services for each other generally at cost in compliance with FERC and BPU affiliate rules.

(B) Services provides and bills administrative services to PSE&G at cost. In addition, PSE&G has other payables to Services, including amounts related to certain common costs, which Services pays on behalf of PSE&G

.

(C) PSEG pays net wages and payroll taxes and receives reimbursement from its affiliated companies for their respective portions. PSEG and its subsidiaries file a consolidated federal income tax return and PSEG and PSE&G file state income tax returns, some of which are combined or unitary. Income taxes are allocated to PSEG's subsidiaries in accordance with a tax allocation agreement whereby each PSEG subsidiary's current and deferred tax expense is computed on a stand-alone basis. Each subsidiary is allocated an amount of tax similar to that which would be paid if it filed a separate income tax return, except for certain tax attributes. If the result is a net tax liability, such amount shall be paid to PSEG. If there are NOLs and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) PSE&G has advanced working capital to Services. The amount is included in Other Noncurrent Assets on PSE&G's Balance Sheets.

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

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	42,398,447,949	28,584,041,091
4	Property Under Capital Leases	83,765,120	
5	Plant Purchased or Sold		
6	Completed Construction not Classified	5,156,887,055	4,805,038,279
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	47,639,100,124	33,389,079,370
9	Leased to Others		
10	Held for Future Use	79,317,913	79,221,633
11	Construction Work in Progress	1,227,245,837	1,108,548,629
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	48,945,663,874	34,576,849,632
14	Accum Prov for Depr, Amort, & Depl	9,598,454,954	6,622,150,173
15	Net Utility Plant (13 less 14)	39,347,208,920	27,954,699,459
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	9,500,848,249	6,620,889,317
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	97,606,705	1,260,856
22	Total In Service (18 thru 21)	9,598,454,954	6,622,150,173
23	Leased to Others		
24	Depreciation		—
25	Amortization and Depletion		—
26	Total Leased to Others (24 & 25)	—	—
27	Held for Future Use		
28	Depreciation		—
29	Amortization		—
30	Total Held for Future Use (28 & 29)	—	—
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		—
33	Total Accum Prov (equals 14) (22,26,30,31,32)	9,598,454,954	6,622,150,173

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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
13,462,014,454				352,392,404	3
	83,765,120				4
					5
350,970,804				877,972	6
					7
13,812,985,258	83,765,120	—	—	353,270,376	8
					9
96,280					10
43,289,669				75,407,539	11
					12
13,856,371,207	83,765,120	—	—	428,677,915	13
2,777,135,841				199,168,940	14
11,079,235,366	83,765,120	—	—	229,508,975	15
					16
					17
2,760,728,323				119,230,609	18
					19
					20
16,407,518				79,938,331	21
2,777,135,841	—	—	—	199,168,940	22
					23
—	—				24
—	—				25
—	—	—	—	—	26
					27
—	—				28
—	—				29
—	—	—	—	—	30
					31
—	—				32
2,777,135,841	—	—	—	199,168,940	33

FOOTNOTE DATA

Schedule Page: 201 Line No.: 4 Column: e

For regulatory reporting purposes, in accordance with FERC Docket No. AI19-1-000, Operating Lease Right-of-Use Assets are included in FERC account 101.1 Property Under Capital Leases. The entire balance in FERC account 101.1 Property Under Capital Leases at December 31, 2025 is comprised of these capitalized operating leases, with no impact on existing ratemaking treatment and practices.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

ELECTRIC PLANT IN SERVICE (Account 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. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. 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)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	—	
3	(302) Franchises and Consents	—	
4	(303) Miscellaneous Intangible Plant	272,348,473	6,895,881
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	272,348,473	6,895,881
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	—	
9	(311) Structures and Improvements	—	
10	(312) Boiler Plant Equipment	—	
11	(313) Engines and Engine-Driven Generators	—	
12	(314) Turbogenerator Units	—	
13	(315) Accessory Electric Equipment	—	
13.1	(315.1) Computer Hardware	—	
13.2	(315.2) Computer Software	—	
13.3	(315.3) Communication Equipment	—	
14	(316) Misc. Power Plant Equipment	—	
15	(317) Asset Retirement Costs for Steam Production	—	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	—	—
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	—	
19	(321) Structures and Improvements	—	
20	(322) Reactor Plant Equipment	—	
21	(323) Turbogenerator Units	—	
22	(324) Accessory Electric Equipment	—	
22.1	(324.1) Computer Hardware	—	
22.2	(324.2) Computer Software	—	
22.3	(324.3) Communication Equipment	—	
23	(325) Misc. Power Plant Equipment	—	
24	(326) Asset Retirement Costs for Nuclear Production	—	
25	TOTAL Nuclear Production Plant (Enter Total of Lines 18 thru 24)	—	—
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	—	
28	(331) Structures and Improvements	—	
29	(332) Reservoirs, Dams, and Waterways	—	
30	(333) Water Wheels, Turbines, and Generators	—	
31	(334) Accessory Electric Equipment	—	
31.1	(334.1) Computer Hardware	—	
31.2	(334.2) Computer Software	—	
31.3	(334.3) Communication Equipment	—	
32	(335) Misc. Power PLant Equipment	—	
33	(336) Roads, Railroads, and Bridges	—	
34	(337) Asset Retirement Costs for Hydraulic Production	—	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	—	—
35.1	D. Other Production Plant		
35.2	(338.1) Land and Land Rights	—	—

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

distributions of these tentative classifications in columns (c) and (d), including the 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.

7. 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, 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.
8. 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 requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase,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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			—		2
			—		3
—	—	(279,244,354)	—		4
—	—	(279,244,354)	—		5
					6
					7
			—		8
			—		9
			—		10
			—		11
			—		12
			—		13
			—		13.1
			—		13.2
			—		13.3
			—		14
			—		15
—	—	—	—		16
					17
			—		18
			—		19
			—		20
			—		21
			—		22
			—		22.1
			—		22.2
			—		22.3
			—		23
			—		24
—	—	—	—		25
					26
			—		27
			—		28
			—		29
			—		30
			—		31
			—		31.1
			—		31.2
			—		31.3
			—		32
			—		33
			—		34
—	—	—	—		35
					35.1
—	—	—	—		35.2

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

ELECTRIC PLANT IN SERVICE (Account 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. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. 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)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
35.3	(338.2) Structures and Improvements	—	
35.5	(338.4) Solar Panels	—	—
35.6	(338.5) Collector System	—	—
35.7	(338.6) Generator Step-up Transformers (GSU)	—	
35.8	(338.7) Inverters	—	1,571,755
35.9	(338.8) Other Accessory Electrical Equipment	—	—
35.10	(338.9) Computer Hardware	—	—
35.11	(338.10) Computer Software	—	—
35.12	(338.11) Communication Equipment	—	—
35.13	(338.12) Miscellaneous Power Plant Equipment	—	—
35.14	(338.13) Asset Retirement Costs for Solar Production	—	—
35.15	TOTAL Solar Production Plant (Enter Total of lines 35.2 thru 35.14)	—	1,571,755
35.16	E. Wind Production Plant		
35.17	(338.20) Land and Land Rights	—	
35.18	(338.21) Structures and Improvements	—	
35.20	(338.23) Wind Turbines	—	
35.21	(338.24) Wind Towers and Fixtures	—	
35.23	(338.26) Collector System	—	
35.24	(338.27) Generator Step-up Transformers (GSU)	—	
35.25	(338.28) Inverters	—	
35.26	(338.29) Other Accessory Electrical Equipment	—	
35.27	(338.30) Computer Hardware	—	
35.28	(338.31) Computer Software	—	
35.29	(338.32) Communication Equipment	—	
35.30	(338.33) Miscellaneous Power Plant Equipment	—	
35.31	(338.34) Asset Retirement Costs for Wind Production	—	
35.32	TOTAL Wind Production Plant (Enter Total of lines 35.17 thru 35.31)	—	—
35.33	F. Other Renewable Production Plant		
35.34	(339.1) Land and Land Rights	—	
35.35	(339.2) Structures and Improvements	—	
35.36	(339.3) Fuel Holders	—	
35.37	(339.4) Boilers	—	
35.39	(339.6) Generators	—	
35.41	(339.8) Other Accessory Electrical Equipment	—	
35.42	(339.9) Computer Hardware	—	
35.43	(339.10) Computer Software	—	
35.44	(339.11) Communication Equipment	—	
35.45	(339.12) Miscellaneous Power Plant Equipment	—	
35.46	(339.13) Asset Retirement Costs for Other Renewable Production	—	
35.47	TOTAL Other Renewable Production Plant (Enter Total of lines 35.34 thru 35.46)	—	—
36	D. Other Production Plant		
37	(340) Land and Land Rights	—	—
38	(341) Structures and Improvements	—	—
39	(342) Fuel Holders, Products, and Accessories	—	—
40	(343) Prime Movers	—	—
41	(344) Generators	604,394,472	—

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

distributions of these tentative classifications in columns (c) and (d), including the 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.

7. 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, 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.
8. 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 requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase,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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
	—		—		35.3
—	—	604,394,472	604,394,472		35.5
—	—	—	—		35.6
—	—	13,178,581	13,178,581		35.7
2,875,638	—	23,501,886	22,198,003		35.8
—	—	2,599,734	2,599,734		35.9
—	—	—	—		35.10
—	—	4,441,216	4,441,216		35.11
246,102	—	1,604,553	1,358,451		35.12
—	—	—	—		35.13
—	—	—	—		35.14
3,121,740	—	649,720,442	648,170,457		35.15
					35.16
			—		35.17
			—		35.18
			—		35.20
			—		35.21
			—		35.23
			—		35.24
			—		35.25
			—		35.26
			—		35.27
			—		35.28
			—		35.29
			—		35.30
			—		35.31
—	—	—	—		35.32
					35.33
			—		35.34
			—		35.35
			—		35.36
			—		35.37
			—		35.39
			—		35.41
			—		35.42
			—		35.43
			—		35.44
			—		35.45
			—		35.46
—	—	—	—		35.47
					36
—	—	—	—		37
—	—	—	—		38
—	—	—	—		39
—	—	—	—		40
—	—	(604,394,472)	—		41

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

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4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. 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)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
42	(345) Accessory Electric Equipment	40,851,806	31,149
42.1	(345.1) Computer Hardware	—	
42.2	(345.2) Computer Software	—	
42.3	(345.3) Communication Equipment	—	
43	(346) Misc. Power Plant Equipment	—	—
44	(347) Asset Retirement Costs for Other Production	3,392,945	—
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	648,639,223	31,149
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, 35.15, 35.32, 35.47, and 45)	648,639,223	31,149

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

distributions of these tentative classifications in columns (c) and (d), including the 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.

7. 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, 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.
8. 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 requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase,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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
—	—	(40,884,755)	(1,800)		42
	—		—		42.1
	—		—		42.2
	—		—		42.3
—	—	—	—		43
—	—	—	3,392,945		44
—	—	(645,279,227)	3,391,145		45
—	—	(645,279,227)	3,391,145		46

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	341,779,560	67,353,134
48.2	(351.1) Computer Hardware	—	5,064,805
48.3	(351.2) Computer Software	—	2,079,681
48.4	(351.3) Communication Equipment	—	33,857,259
49	(352) Structures and Improvements	575,337,578	40,935,805
50	(353) Station Equipment	8,856,607,479	230,374,084
51	(354) Towers and Fixtures	1,525,818,837	5,845,483
52	(355) Poles and Fixtures	572,090,499	27,008,283
53	(356) Overhead Conductors and Devices	2,967,872,762	262,880,190
54	(357) Underground Conduit	574,889,055	23,971,091
55	(358) Underground Conductors and Devices	2,407,080,521	46,241,629
56	(359) Roads and Trails	6,002,572	3,134,381
57	(359.1) Asset Retirement Costs for Transmission Plant	(31,718)	—
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	17,827,447,145	748,745,825
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	51,702,863	80,021
61	(361) Structures and Improvements	293,955,036	(596,981)
62	(362) Station Equipment	1,816,260,547	152,179,628
63.1	(363.1) Computer Hardware	—	2,301,090
63.2	(363.2) Computer Software	—	7,591,099
63.3	(363.3) Communication Equipment	—	19,844,717
64	(364) Poles, Towers, and Fixtures	1,238,184,510	138,418,892
65	(365) Overhead Conductors and Devices	3,488,437,555	354,538,930
66	(366) Underground Conduit	533,011,549	26,792,270
67	(367) Underground Conductors and Devices	1,593,592,669	54,805,813
68	(368) Line Transformers	1,816,951,919	147,589,163
69	(369) Services	566,607,927	9,519,467
70	(370) Meters	466,683,678	21,288,457
71	(371) Installations on Customer Premises	—	—
72	(372) Leased Property on Customer Premises	—	—
73	(373) Street Lighting and Signal Systems	533,273,881	38,251,233
74	(374) Asset Retirement Costs for Distribution Plant	140,659,098	—
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	12,539,321,232	972,603,799
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights	—	
78	(381) Structures and Improvements	—	
79	(382) Computer Hardware	—	
80	(383) Computer Software	—	
81	(384) Communication Equipment	—	
82	(385) Miscellaneous Regional Transmission and Market Operation Plant	—	
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper	—	
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)	—	—
84.1	6. ENERGY STORAGE PLANT		
84.2	(387.1) Land and Land Rights	—	
84.3	(387.2) Structures and Improvements	—	
84.4	(387.3) Energy Storage Equipment	—	
84.6	(387.5) Collector System	—	
84.7	(387.6) Generator Step-up Transformers (GSU)	—	
84.8	(387.7) Inverters	—	
84.9	(387.8) Computer Hardware	—	
84.10	(387.9) Computer Software	—	
84.11	(387.10) Communication Equipment	—	
84.12	(387.11) Miscellaneous Energy Storage Equipment	—	
84.13	(387.12) Asset Retirement Costs for Energy Storage	—	
84.14	TOTAL Energy Storage Plant (Total lines 84.2 thru 84.13)	—	—

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
118	1	732,152	409,864,729		48
—	—	918,163	5,982,968		48.2
—	—	1,704,500	3,784,181		48.3
(6,166)	—	58,350,194	92,213,619		48.4
—	—	(213,502)	616,059,881		49
12,452,656	29,178	81,843	9,074,639,928		50
—	—	—	1,531,664,320		51
—	—	—	599,098,782		52
2,768,453	—	—	3,227,984,499		53
7,804	—	—	598,852,342		54
216,060	—	—	2,453,106,090		55
—	—	—	9,136,953		56
—	(358,200)	—	(389,918)		57
15,438,925	(329,021)	61,573,350	18,621,998,374		58
					59
—	—	—	51,782,884		60
(338,428)	(20,372)	—	293,676,111		61
25,186,218	(60,624)	—	1,943,193,333		62
4,672	—	10,277,189	12,573,607		63.1
12,608,707	—	274,603,942	269,586,334		63.2
257,277	—	97,347,455	116,934,895		63.3
274,762	(101,610)	—	1,376,227,030		64
20,354,993	(228,037)	(474,155)	3,821,919,300		65
—	(72,985)	—	559,730,834		66
422,049	(111,274)	—	1,647,865,159		67
9,288,409	(97,137)	5	1,955,155,541		68
67,747	(4,780)	—	576,054,867		69
9,510,786	—	—	478,461,349		70
—	—	—	—		71
—	—	—	—		72
36,939,235	(1,364)	—	534,584,515		73
561,623	(9,031,832)	—	131,065,643		74
115,138,050	(9,730,015)	381,754,436	13,768,811,402		75
					76
			—		77
			—		78
			—		79
			—		80
			—		81
			—		82
			—		83
—	—	—	—		84
					84.1
			—		84.2
			—		84.3
			—		84.4
			—		84.6
			—		84.7
			—		84.8
			—		84.9
			—		84.10
			—		84.11
			—		84.12
			—		84.13
—	—	—	—		84.14

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	246,311	—
87	(390) Structures and Improvements	44,644,114	(947)
88	(391) Office Furniture and Equipment	25,392,287	(164,597)
89	(392) Transportation Equipment	216,881,334	12,992,529
90	(393) Stores Equipment	1,324,425	167,460
91	(394) Tools, Shop and Garage Equipment	24,365,039	3,270,089
92	(395) Laboratory Equipment	2,725,641	204,610
93	(396) Power Operated Equipment	40,823,387	449,866
94	(397.1) Computer Hardware	—	—
94.1	(397.2) Computer Software	—	—
94.2	(397.3) Communication Equipment	170,071,283	(13,244,911)
95	(398) Miscellaneous Equipment	2,990,807	314,315
96	SUBTOTAL (Enter Total of lines 86 thru 95)	529,464,628	3,988,414
97	(399) Other Tangible Property	—	—
98	(399.1) Asset Retirement Costs for General Plant	373,773	—
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	529,838,401	3,988,414
100	TOTAL (Accounts 101 and 106)	31,817,594,474	1,733,836,823
101	(102) Electric Plant Purchased (See Instr. 8)	—	
102	(Less) (102) Electric Plant Sold (See Instr. 8)	—	
103	(103) Experimental Plant Unclassified	—	
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	31,817,594,474	1,733,836,823

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					85
—	(750,000)	—	(503,689)		86
—	1	—	44,643,168		87
1,276,970	—	(11,195,352)	12,755,368		88
7,295,157	—	—	222,578,706		89
40,686	—	—	1,451,199		90
7,725,383	—	—	19,909,745		91
981,017	—	—	1,949,234		92
1,007,730	—	—	40,265,523		93
—	—	—	—		94
—	—	—	—		94.1
487,950	—	(155,484,147)	854,275		94.2
819,877	—	—	2,485,245		95
19,634,770	(749,999)	(166,679,499)	346,388,774		96
—	—	—	—		97
—	(54,555)	—	319,218		98
19,634,770	(804,554)	(166,679,499)	346,707,992		99
153,333,485	(10,863,590)	1,845,148	33,389,079,370		100
			—		101
			—		102
			—		103
153,333,485	(10,863,590)	1,845,148	33,389,079,370		104

FOOTNOTE DATA

Schedule Page: 205 Line No.: 4-35.11 Column: f-g

Data field was updated to correctly state previously reported amounts.

Schedule Page: 206 Line No.: 94-94.2 Column: b-c

Data field was updated to correctly state previously reported amounts.

Schedule Page: 207 Line No.: 63.2-94.2 Column: d-g

Data field was updated to correctly state previously reported amounts.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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 $250,00 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 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				
3	Land, Pemberton, NJ	06/01/1991	06/01/2029	491,215
4	Land West Hampton NJ	05/30/2017	06/01/2033	1,189,325
5	Land, Bennetts Lane, NJ	08/31/2018	06/01/2032	1,171,079
6	Land, Mt. Rose, NJ	08/01/2019	06/01/2032	954,101
7	Land, Prospect Park, NJ	07/29/2022	06/01/2028	9,327,706
8	Land, East Rutherford, NJ	07/29/2022	06/01/2026	3,307,807
9	Land, Maple Shade, NJ	06/01/2022	06/01/2027	1,614,279
10	Land, Piscataway, NJ	09/08/2023	06/01/2031	2,864,675
11	Land (219) , South Orange, NJ	06/26/2025	06/01/2033	6,095,927
12	Land, Cherry Hill, NJ	07/09/2024	06/01/2030	5,587,863
13	Land, North Bordentown, NJ	03/20/2025	06/01/2031	2,769,805
14	Land, Paramus, NJ	10/24/2025	06/01/2033	14,650,779
15	Land (215), South Orange, NJ	12/03/2025	06/01/2033	3,626,544
16	Land, Hillside, NJ	12/17/2025	06/01/2031	4,541,172
17	Minor Items	06/01/1966	06/01/2029	163,163
18				
19				
20				
21	Other Property:			
22				
23	Station Equipment	12/31/2015	06/01/2032	16,048,056
24	Overhead Conductors & Devices	12/31/2016	06/01/2026	1,085,479
25	Underground Conduit	06/01/2021	06/01/2031	1,292,988
26	Poles	12/01/2024	06/01/2031	2,439,670
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
40				
41				
42				
43				
44				
45				
46				
47	**Total**			**79,221,633**

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 Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	s2537 Cnstrct Bergen Point 69/13kV	84,551,987
2	s2318 Central Av (Ninth Ave) 69kV N	49,549,335
3	Property Purchase of 40 Cragwood Rd.	41,475,246
4	s2491 Construct Elizabeth 69/4kV Su	39,059,366
5	EMS Replacement	37,865,094
6	IAP - IP - Teaneck Substation	33,540,103
7	s1722 Cnstrct Orange Heights 230/69	32,111,079
8	IAP - IP - McLean Blvd Substation	30,654,944
9	s2729 Cnstrct South Clinton Ave 69k	30,623,648
10	b1099- NLPR Purchase Berger Property	27,596,380
11	s2318 Central Av (Ninth Ave)69kV Ntwk-D.	27,398,084
12	s2415 Constrct Cliffs 69/13kV Class	24,887,273
13	s1823 Cnstrct Roselle 69kV Class H	24,323,958
14	s0483 Clay Street Area 69kV Network	24,252,761
15	s2729 Cnstrct South Clinton Ave 69kV - D	23,556,965
16	s0934 Construct Port Street 69kV St	21,861,860
17	EV Fleet Electrification-Transmissi	20,426,385
18	s2385 Construct Pennsauken 230kV-13	19,361,052
19	Medford & Southhampton 69kV Voltage	19,028,662
20	b3755 Cnvrt Locust St 69kV-Ring Bus	18,139,343
21	West Orange 26kV Lifecycle - D	17,815,674
22	s2715 Upgrade Garfield Ave 69-13-4k	17,435,665
23	b3758 Harts Ln 69kV Voltage Violati	15,125,025
24	s2715 Upgrade Garfield Ave 69-13-4kV- D.	14,351,291
25	TLC Blkt- Minor Trans Facility Upgr	13,970,073
26	s2483 Construct Spring Valley 69kV-13kV	13,445,834
27	Salesforce - Capital	13,341,839
28	s2537 Cnstrct Bergen Point 69/13kV - D	13,109,097
29	Replace Overhead Right-Of-Way Bridg	12,954,494
30	b3756 Maple Shade 69kV Voltage Drop	11,873,816
31	Reconfigure West Essex Load Pocket - D	11,368,351
32	s2568 Upgrade Fairview 69kV-13kV Su	10,825,828
33	s2564 Cnstrct Oak Tree 230/13kV - T	9,507,714
34	s1823 Cnstrct Roselle 69kV Class H Sub-D	9,450,817
35	Construct Blair Road 230/69kV Station-T	8,958,932
36	Project Administration	8,739,435
37	s2951 Prospect Pk 69-13kV Class H-T	8,569,016
38	s2276 Cnstrct Rancocas 230/13kV Cls H -D	8,290,861
39	NERC CIP v14 Compliance - 2025	8,205,957
40	EV Fleet Electrification - Distrib Elec	7,978,348
41	OP - Palisades 26kv Load Growth	7,917,444
42	s2904 Cnstrct Ridge Rd Area Class H	7,828,312
43	TOTAL	1,108,548,629

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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 Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
42.01	s3090 Cnstrct Harlingen Area Class	6,901,296
42.02	b3855 Constr 230kV XLPE Cedar to Ja	6,759,718
42.03	Kenilworth Customer (Onyx) 69kV Inter-T	6,509,271
42.04	s2491 Construct Elizabeth 69/4kV Sub - D	6,124,480
42.05	Central Elizabeth	6,043,254
42.06	s3008 South Edison Class H Substati	5,854,843
42.07	TLC Insultor Assmbly Rplcmnt- 5038	5,211,493
42.08	s2415 Constrct Cliffs 69/13kV Class-H -D	5,144,035
42.09	s1722 Cnstrct Orange Heights 230/69kV -D	5,050,130
42.10	s2385 Construct Pennsauken 230kV-13kV- D	5,041,074
42.11	Upgrade Greenville Sub 4kV System - D	4,872,829
42.12	Replace Ridgefield T30 230/13kV Xfr	4,835,444
42.13	Service to 55 Hudson Street	4,712,087
42.14	Bridgewater Flood Mitigation - D	4,674,502
42.15	2025 ROW Boardwalks Blanket	4,633,348
42.16	Lafayette Road Class H Contingency-	4,487,823
42.17	Lawrence-Trenton NGR & NRP Upgrade	3,961,786
42.18	syyyy Enhanced PhysicalSecurity-Tra	3,855,763
42.19	Construct Keasbey 69-13kV Class H - T	3,842,077
42.20	s3007 Replace G-709 69kV HPFF	3,807,858
42.21	s2904 Cnstrct Ridge Rd Area Class H - D	3,474,408
42.22	System Spare Transformers (345 & 23	3,380,860
42.23	b3025 Doremus Place N-1-1 Reliability- D	3,359,411
42.24	Service to 400 Luis Marin Blvd.	3,353,784
42.25	IAP - IP - 40th Street Substation	3,277,279
42.26	Upgrd Fiber & Relays Ckt 5038 & New	3,133,788
42.27	s3010 Cnstrct Van Winkle 69/13kV Cl	2,926,020
42.28	Land Purchase for Roselle 69/13kV S	2,919,137
42.29	Eliminate Unit Substation- Scotch Plains	2,911,006
42.30	s1022 Construct Ironbound 69kV Sub-	2,823,433
42.31	Service to ZT Systems	2,540,101
42.32	Medford & Southhampton 69kV Voltage Drop	2,531,032
42.33	Pipe Cable Monitoring Blanket	2,491,819
42.34	s3008 South Edison Class H Substation -D	2,488,817
42.35	s2564 Cnstrct Oak Tree 230/13kV - D	2,463,668
42.36	Bridgewater Flood Mitigation - T	2,331,214
42.37	TLC Insultor Assmbly Rplcmnt-Non-LD	2,314,199
42.38	Purchase (2) 69x26-13kV Mobile Uni	2,221,347
42.39	Service to 35 Cottage Street (SB)	2,111,604
42.40	Serv to 189 Phillips St(ScholarsVillage)	2,077,854
42.41	Purch Sys Spare Xfmr (230-138kV, 550M	2,074,421
42.42	s3010 Cnstrct Van Winkle 69/13kV Cls H-D	1,992,025
43	TOTAL	1,108,548,629

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 Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
42.43	b2933.1-3 Construct Springfield Rd 69kV	1,884,683
42.44	2014 Distribution SF Blanket- Statewide	1,868,618
42.45	syyyy Install Neutral Resistor Lawrence	1,820,378
42.46	s2316 Cnstrct Livingston 230/13kV ClsH-D	1,794,887
42.47	Service to Princeton University 69KV (T)	1,792,424
42.48	Install 345/230kV Xfrmr Linden (CJG	1,784,016
42.49	Service to 20 French Street	1,765,969
42.50	IAP-IP-Totowa Substation	1,735,006
42.51	ER Blkt T- NERC CIP v5 Compliance-	1,657,989
42.52	3 Teri Lane Interior Refresh	1,633,143
42.53	ER Blkt T- NERC CIP v14 Compliance- Cen	1,609,981
42.54	s2951 Prospect Pk 69-13kV Class H-D	1,525,091
42.55	OP - Direct IS - WHS8042	1,514,854
42.56	b2436.90 Farragut-Hudson Crkt B-3402	1,513,919
42.57	Purch 230-69kV 300MVA Xfrmr - Keasb	1,461,566
42.58	s2413 Cnstrct Nicholson (Audubon) - D	1,457,793
42.59	b3794 Rplc Waldwick Sw Shunt Reacto	1,412,224
42.60	Lafayette Road Class H Contingency	1,410,522
42.61	Bayway 345kV #3 Reactor Replacement	1,377,890
42.62	2014 Trans OPGW Replacement Program	1,352,869
42.63	Hadley Rd Conf. Rm Upgrade	1,304,304
42.64	2018 TLC Blanket Relay Palisades	1,174,337
42.65	Reconfigure Waldwick 13kV Circuits	1,154,564
42.66	syyyy SPCC Remediation Program- T (Cen)	1,152,320
42.67	s1368.1-3 Construct Penns Neck 69 kV-T	1,091,758
42.68	MMC Supply Switching Station	1,026,096
42.69	s3184.1 Cnstrct 3rd Xfrmr South Sec	1,022,006
42.70	DILO SF6 Gas Detection System Insta	1,014,807
42.71	Minor Items	24,386,929
42.72	—	—
42.73	—	—
42.74	—	—
42.75	—	—
42.76	—	—
42.77	—	—
42.78	—	—
42.79	—	—
42.80	—	—
42.81	—	—
42.82	—	—
42.83	—	—
42.84	—	—
42.85	—	—
42.86	—	—
43	TOTAL	1,108,548,629

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 9d), 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	6,034,740,087	6,034,740,087	—	—
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	788,662,649	788,662,649		
4	(403.1) Depreciation Expense for Asset Retirement Costs	—			
5	(413) Exp. of Elec. Plt. Leas. to Others	—			
6	Transportation Expenses-Clearing	—			
7	Other Clearing Accounts	—			
8	Other Accounts (Specify, details in footnote):	—			
9		—			
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	788,662,649	788,662,649	—	—
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(152,771,742)	(152,771,742)		
13	Cost of Removal	(110,195,805)	(110,195,805)		
14	Salvage (Credit)	8,169,269	8,169,269		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(254,798,278)	(254,798,278)	—	—
16	Other Debit or Cr. Items (Describe, details in footnote):	52,284,859	52,284,859		
17	Insurance & Misc.	—			
18	Book Cost or Asset Retirement Costs Retired	—			
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	6,620,889,317	6,620,889,317	—	—
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	—			
21	Nuclear Production	—			
22	Hydraulic Production-Conventional	—			
23	Hydraulic Production-Pumped Storage	—			
23.1	Solar Production	424,980,396	424,980,396		
23.2	Wind Production	—			
23.3	Other Renewable Production	—			
24	Other Production	—			
25	Transmission	2,872,367,189	2,872,367,189		
26	Distribution	3,140,483,279	3,140,483,279		
27	Regional Transmission and Market Operation	—			
27.1	Energy Storage	—			
28	General	183,058,453	183,058,453		
29	TOTAL (Enter Total of lines 20 thru 28)	6,620,889,317	6,620,889,317	—	—

FOOTNOTE DATA

Schedule Page: 219 Line No.: 3 Column: c

Page 336 Depreciation Expense	787,007,076
Add capitalized depreciation	16,008,361
Less common depreciation - electric	(10,835,555)
Add depreciation of regulatory accounts	(3,517,233)
Total Adjustments	1,655,573
Page 219 Depreciation Expense	788,662,649

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 there under 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)	Name of Subsidiary (For Lines 1-41, enter the name of the pertinent subsidiary, for line 42, report the Total Cost of Account 123.1) (a1)	Type of Investment (XBRL ONLY: Select the nature of the investment, or choose an "Unspecified Investment" from the list below) (a2)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	NJ Properties	NJ Properties	Subsidiary Company Subheading	1990-10-19		—
2	Common Stock	NJP Common 1	Captial Stock			1,000
3	Contributed Capital	NJP Contribution 1	Capital Contribution			270,216
4						—
5	Public Service Corporation of NJ	Public Service Corporation of NJ	Subsidiary Company Subheading	1991-05-20		—
6	Common Stock	PSC Common 2	Captial Stock			1,000
7	Retained Earnings	PSC RE 1	Retained Earnings			—
8						—
9	Public Service New Millennium Development Fund LLC	Public Service New Millennium Development Fund LLC	Subsidiary Company Subheading	1996-10-22		—
10	Common Stock	PSNM Common 3	Captial Stock			10,000
11	Contributed Capital	PSNM Contribution 2	Capital Contribution			430,766
12	Retained Earnings	PSNM RE 2	Retained Earnings			(440,610)
13						—
14	PSE&G Area Development LLC	PSE&G Area Development LLC	Subsidiary Company Subheading	2000-05-03		—
15	Contributed Capital	PSE&G AD Contribution 3	Captial Stock			12,195,542
16	Retained Earnings	PSE&G AD RE 3	Retained Earnings			(1,190,776)
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		$11,277,138.00		TOTAL	11,277,138

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 form investments, including such revenues form 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 of 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
		1,000		2
		270,216		3
				4
				5
		1,000		6
				7
				8
				9
		10,000		10
		430,766		11
—		(440,610)		12
				13
				14
—	—	12,195,542		15
—	—	(1,190,776)		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
—	—	11,277,138	—	42

MATERIALS AND SUPPLIES

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.

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	Balance Beginning of Year	Balance End of Year	Department or Departments which Use Material
	(a)	(b)	(c)	(d)
1	Fuel Stock (Account 151)	—		
2	Fuel Stock Expenses Undistributed (Account 152)	—		
3	Residuals and Extracted Products (Account 153)	—		
4	Plant Materials and Operating Supplies (Account 154)	—		
5	Assigned to - Construction (Estimated)	493,299,782	470,060,845	
6	Assigned to - Operations and Maintenance	—		
7	Production Plant (Estimated)	—		
8	Transmission Plant (Estimated)	28,702,185	33,155,259	
9	Distribution Plant (Estimated)	119,763,472	109,666,264	
10	Regional Transmission and Market Operation Plant (Estimated)	—		
10.1	Energy Storage Plant (Estimated)	—		
11	Assigned to - Other (provide details in footnote)	—		
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	641,765,439	612,882,368	
13	Merchandise (Account 155)	—		
14	Other Materials and Supplies (Account 156)	—		
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)	—		
16	Stores Expense Undistributed (Account 163)	—		
17		—		
18		—		
19		—		
20	TOTAL Materials and Supplies (Per Balance Sheet)	641,765,439	612,882,368	

FOOTNOTE DATA

Schedule Page: 227 Line No.: 5 Column: b

Transmission Plant (Estimated)	72,580,063
Distribution Plant (Estimated)	420,719,719
Assigned to Construction	493,299,782

Schedule Page: 227 Line No.: 5 Column: c

Transmission Plant (Estimated)	63,898,833
Distribution Plant (Estimated)	406,162,012
Assigned to Construction	470,060,845

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	—	—	—	—	—
3	—	—	—	—	—
4	—	—	—	—	—
5	—	—	—	—	—
6	—	—	—	—	—
7	—	—	—	—	—
8	—	—	—	—	—
9	—	—	—	—	—
10	—	—	—	—	—
11	—	—	—	—	—
12					
13					
14					
15					
16					
17					
18					
19					
20	**Total Transmission Studies**	**—**		**—**	
21	**Generation Studies**				
22	PJM Merchant Bergen 230kV	7,018	—	—	—
23	PJM Merchant Salem 500kV	2,347	—	—	—
24	PJM Merchant Linden 138kV	6,690	—	—	—
25	PJM Merchant Linden 230kV	9017	—	—	—
26	—	—	—	—	—
27	—	—	—	—	—
28	—	—	—	—	—
29	—	—	—	—	—
30	—	—	—	—	—
31	—	—	—	—	—
32	—	—	—	—	—
33	—	—	—	—	—
34					
35					
36					
37					
38					
39	**Total Generation Studies**	**25,072**		**—**	
40	**Grand Total**	**25,072**	**186/456**	**—**	**186/456**

FOOTNOTE DATA

Schedule Page: 231 Line No.: 40 Column: b

Transmission Study records net revenues and costs as follows:

Grand Total (Pg.231)	
Line 40d	—
Line 40b	25,072
Net Total page 231	25,072
Net Total Charged to 456	—
Net Total Charged to BS 186	25,072
	25,072

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/ Year) (f)
				Written off During the Quarter/ Year Account Charged (d)	Written off During the Period Amount (e)	
1	**Distribution specific regulatory assets recovered under approved NJBPU recovery mechanisms:**	—				—
2	Manufacturing Gas Plant (MGP) Remediation Costs	312,347,084	43,485,209	407, 253	75,238,728	280,593,565
3	Clean Energy Program (CEP)	358,037,128	224,025,282	908, 182	248,729,676	333,332,734
4	Green Programs Recovery Clause (GPRC)	1,250,556,950	972,697,168	182.3, 254, 431, 456, 908	628,737,138	1,594,516,980
5	Solar Pilot Recovery Charge (SPRC)	40,189	79,994	254, 124	1,398,261	(1,278,078)
6	COVID ED & GD Deferred Incremental Costs	130,703,671	45,624,881	908	66,879,421	109,449,131
7	Tax Adjustment Credit (TAC)	25,833,332	—	254	25,833,332	—
8	Conservation Incentive Program (CIP - ED & GD)	261,407,776	191,301,013	182, 456, 495	325,703,203	127,005,586
9	**Electric & Gas default energy supply to distribution customers recovered under approved NJBPU recovery mechanisms:**	—				—
10	Underrecovered Electric Costs (BGS)	26,927,570	2,055,192	182, 254, 955	3,542,882	25,439,880
11	Deferred Gas Fuel Costs (BGSS-F)	9,107,739	4,904,566	182, 254, 804	—	14,012,305
12	**Distribution specific regulatory assets recovered under NJBPU 2024 Distribution Base Rate Case Order:**	—	—			—
13	2024 Base Rate Case (BRC) approved Regulatory Assets (Storm costs, BPU Management Audit fees and Rate Case Fees)	107,883,883	18,414,795	182, 908	37,601,910	88,696,768
14	Clean Energy Future-Energy Cloud (CEF-EC/ Elec AMI)	232,681,667	145,556	182,403, 407.3, 908	26,639,789	206,187,434
15	Clean Energy Future-Electric Vehicle (CEF-EV)	56,736,549	40,883,645	182, 403, 908	5,643,430	91,976,764
16	**Other Distribution regulatory assets deferred for future recovery under approved NJBPU Orders:**	—				—
17	BGS DCFC Pilot Program Recovery	179,872	—	182	188,152	(8,280)
18	Benchmarking Deferred Cost	95,493	335,777		—	431,270
19	Temporary Supply Offset Clause (Affordability Credit)	—	41,769,590		—	41,769,590
20	**Transmission Formula Rate regulatory asset:**	—				—
21	Transmission Formula Rate True Ups	32,273,152	61,155,719	182, 495	40,526,782	52,902,089
22	**Regulatory assets to be recovered in future rates:**	—				—
23	FIN 47 Conditional ARO	221,058,179	19,941,688	101	4,231,891	236,767,976
24	Gas Forward Contract Purchases	—	17,782,432		—	17,782,432
25	Pension and Other Post - Retirement	1,330,162,985	49,299,372	228	166,296,399	1,213,165,958
26	Incurred but not reported claims reserve	43,805,968	18,888,454	925, 935	17,600,230	45,094,192
27	Uncertain Tax Positions	—	—	253	—	—
28	Deferred Income Tax Regulatory Asset	2,228,672,037	1,839,495,586	190, 282, 283, 410.1, 411.1	1,577,808,952	2,490,358,671
29	Time of Use rates costs	—	2,624,209		—	2,624,209
30		—				—
44	TOTAL	6,628,511,224	3,594,910,128		3,252,600,176	6,970,821,176

FOOTNOTE DATA

Schedule Page: 232 Line No.: 12 Column: a

In conjunction with the NJ BPU Order dated October 9, 2024, OAL Docket No. PUC 00926-24, adopting initial decision and stipulation in Docket Nos. ER23120924 and GR23120925, these amounts represent the authorized recovery of previously deferred ED & GD Storm Damage, previously deferred 2021 BPU Mgmt Audit Fees and previously deferred 2023 Rate Case Deferred Cost. These amounts have been grouped and identified as “2024 Base Rate Case Deferrals” and began amortizing on October 15, 2024 in conjunction with the order.

The order also authorized recovery of previously deferred Clean Energy Future – Electric Vehicle (CEF-EV) costs (Line No. 15) and Clean Energy Future – Energy Cloud (CEF-EC / Electric AMI) costs (Line No. 14). These amounts also began amortizing on October 15, 2024 in conjunction with the order.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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 item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits	Balance at Beginning of Year	Debits	CREDITS		Balance at End of Year
				Account Charged	Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Repair & Expense Work Done For Others	27,472,384	84,899,213	various	83,390,738	28,980,859
2		—	—	—	—	—
3		—	—	—		—
4	Commitment Fees	1,292,626	17,459,285	165	17,470,123	1,281,788
5		—	—	—		—
6	Branch Brook Substation	188,000	—	253		188,000
7		—	—	—		—
8	Prepayments	1,330,763	21,058,236	Various	21,219,839	1,169,160
9		—	—	—	—	—
10	Deferred Damage Claims	2,269,271	—	144	278,502	1,990,769
11		—				—
12	Non-Current Taxes Accrued	3,655,974	28,883,360	253 / 283	31,613,825	925,509
13		—				—
14		—				—
15		—				—
16		—				—
17		—				—
18		—				—
19		—				—
20		—				—
21		—				—
22		—				—
23		—				—
24		—				—
25		—				—
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27		—				—
28		—				—
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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	36,209,018				34,536,085

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.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (C)
1	Electric		
2		531,318,651	618,411,608
3		—	
4		—	
5		—	
6		—	
7	Other	—	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	531,318,651	618,411,608
9	Gas		
10		176,708,774	184,092,030
11		—	
12		—	
13		—	
14		—	
15	Other	—	
16	TOTAL Gas (Enter Total of lines 10 thru 15)	176,708,774	184,092,030
17	Other (Specify)	—	
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	708,027,425	802,503,638

Notes

FOOTNOTE DATA

Schedule Page: 234 Line No.: 2 Column: b

OPEB	20,217,754
Gross-up on Excess Deferred Tax Balance	371,574,019
Bad Debt	27,063,623
New Jersey Corporate Business Tax	49,788,772
Customer Advances	10,901,696
Other	51,772,787
Total Electric	531,318,651

Schedule Page: 234 Line No.: 2 Column: c

OPEB	16,520,680
Gross-up on Excess Deferred Tax Balance	440,782,967
Bad Debt	33,957,541
New Jersey Corporate Business Tax	61,238,759
Customer Advances	19,092,920
Other	46,818,741
Total Electric	618,411,608

Schedule Page: 234 Line No.: 10 Column: b

OPEB	1,609,353
Gross-up on Excess Deferred Tax Balance	48,760,176
Bad Debt	15,805,413
New Jersey Corporate Business Tax	105,381,356
Customer Advances	3,954,936
Other	1,197,540
Total Gas	176,708,774

Schedule Page: 234 Line No.: 10 Column: c

OPEB	(957,698)
Gross-up on Excess Deferred Tax Balance	47,527,142
Bad Debt	17,909,710
New Jersey Corporate Business Tax	113,335,305
Customer Advances	4,015,785
Other	2,261,786
Total Gas	184,092,030

Note:
Future rate making filings on which customer rates are determined in whole or in part based on a future period (e.g. forecasted ADIT balances) will be computed in accordance with the rules set forth in IRC regulation section

CAPITAL STOCKS (Account 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 Series (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)			
2	Common Stock	150,000,000		
3				
4				
5	Total	150,000,000		
6	Preferred Stock (Account 204)			
7	Preferred Stock	7,500,000	100.00	
8	Preferred Stock - $25 par	10,000,000	25.00	
9				
10	Total	17,500,000		

CAPITAL STOCKS (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 non-cumulative.
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 Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)	Line No.
						1
132,450,344	892,260,275					2
						3
						4
132,450,344	892,260,275					5
						6
						7
						8
						9
—	—					10

FOOTNOTE DATA

Schedule Page: 250 Line No.: 2 Column: e

(1) All outstanding Common Stock is held by Public Service Enterprise Group Incorporated and is not traded on any stock exchange.

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 debit 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	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	2,155,436,302
3	Increases (Decreases) from Sales of Donations Received from Stockholders	(635.00)
3.1	Rounding	
4	Ending Balance Amount	2,155,435,667
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
7.1		
8	Ending Balance Amount	—
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
11.1		
12	Ending Balance Amount	—
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	
15	Increases (Decreases) Due to Miscellaneous Paid-In Capital	
15.1		
16	Ending Balance Amount	—
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19	Increases (Decreases) in Other Paid-In Capital	
19.1		
20	Ending Balance Amount	—
40	TOTAL	2,155,435,667

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

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.
In column (a), for new issues, give Commission authorization numbers and dates.
For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
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.
For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
In column (b) show the principal amount of bonds or other long-term debt originally issued.
In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
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.
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)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)
1	Bonds (Account 221)						
2	Public Service Electric and Gas Company						
3	First and Refunding Mortgage Bonds						
4	8% 2037		10,000,000		—	—	—
4.01	5% 2037		8,500,000		—	—	—
4.02	Medium Term Notes						
4.03	5.25% 2035		250,000,000		2,145,750	—	787,500
4.04	5.70% 2036		250,000,000		2,175,000	—	1,060,000
4.05	5.80% 2037		350,000,000		2,975,000	—	682,500
4.06	5.375% 2039		250,000,000		2,175,000	—	802,500
4.07	5.50% 2040		300,000,000		2,580,000	—	1,437,000
4.08	3.95% 2042		450,000,000		3,907,527	—	2,893,500
4.09	3.65% 2042		350,000,000		3,183,360	—	1,704,500
4.10	3.80% 2043		400,000,000		3,517,560	—	2,548,000
4.11	4.00% 2044		250,000,000		2,282,200	—	2,372,500
4.12	3.00% 2025		350,000,000		2,690,567	—	360,500
4.13	4.05% 2045		250,000,000		2,296,833	—	1,245,000
4.14	4.15% 2045		250,000,000		2,275,000	—	255,000
4.15	3.80% 2046		550,000,000		4,847,482	—	2,442,000
4.16	2.25% 2026		425,000,000		3,081,811	—	1,398,250
4.17	3.00% 2027		425,000,000		3,217,508	—	1,245,250
4.18	3.60% 2047		350,000,000		3,095,321	—	255,500
4.19	3.70% 2028		375,000,000		2,814,628	—	1,425,000
4.20	4.05% 2048		325,000,000		2,926,844	—	2,011,750
4.21	3.65% 2028		325,000,000		2,329,903	—	52,000
4.22	3.20% 2029		375,000,000		2,796,475	—	1,466,250
4.23	3.85% 2049		375,000,000		3,358,975	—	63,750
4.24	3.20% 2049		400,000,000		3,545,000	—	2,900,000
4.25	2.45% 2030		300,000,000		2,275,000	—	690,000
4.26	3.15% 2050		300,000,000		2,725,000	—	462,000
4.27	2.70% 2050		375,000,000		3,413,927	—	1,530,000
4.28	2.05% 2050		375,000,000		3,307,500	—	2,996,250
33	TOTAL		16,468,500,000				

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

Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
In a footnote, give explanatory (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) principle repaid during year. Give Commission authorization numbers and dates.
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.
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.
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.
Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)	Line No.
						1
						2
						3
1937-06-01	2037-06-01	1937-06-01	2037-06-01	7,462,900	597,032	4
1937-06-01	2037-06-01	1937-06-01	2037-06-01	7,537,800	376,890	4.01
						4.02
2005-07-01	2035-07-01	2005-07-01	2035-07-01	250,000,000	13,125,000	4.03
2006-12-18	2036-12-01	2006-12-18	2036-12-01	250,000,000	14,250,000	4.04
2007-05-14	2037-05-01	2007-05-14	2037-05-01	350,000,000	20,300,000	4.05
2009-11-24	2039-11-01	2009-11-24	2039-11-01	250,000,000	13,437,500	4.06
2010-03-08	2040-03-01	2010-03-08	2040-03-01	300,000,000	16,500,000	4.07
2012-05-07	2042-05-01	2012-05-07	2042-05-01	450,000,000	17,775,000	4.08
2012-09-13	2042-09-01	2012-09-13	2042-09-01	350,000,000	12,775,000	4.09
2013-01-01	2043-01-01	2013-01-01	2043-01-01	400,000,000	15,200,000	4.10
2014-06-02	2044-06-01	2014-06-02	2044-06-01	250,000,000	10,000,000	4.11
2015-05-12	2025-05-15	2015-05-12	2025-05-15	—	3,937,500	4.12
2015-05-12	2045-05-01	2015-05-12	2045-05-01	250,000,000	10,125,000	4.13
2015-11-06	2045-11-01	2015-11-06	2045-11-01	250,000,000	10,375,000	4.14
2016-03-03	2046-03-01	2016-03-03	2046-03-01	550,000,000	20,900,000	4.15
2016-09-13	2026-09-15	2016-09-13	2026-09-15	425,000,000	9,562,500	4.16
2017-05-05	2027-05-15	2017-05-05	2027-05-15	425,000,000	12,750,000	4.17
2017-12-06	2047-12-01	2017-12-06	2047-12-01	350,000,000	12,600,000	4.18
2018-05-04	2028-05-01	2018-05-04	2028-05-01	375,000,000	13,875,000	4.19
2018-05-04	2048-05-01	2018-05-04	2048-05-01	325,000,000	13,162,500	4.20
2018-09-07	2028-09-01	2018-09-07	2028-09-01	325,000,000	11,862,500	4.21
2019-05-08	2029-05-15	2019-05-08	2029-05-15	375,000,000	12,000,000	4.22
2019-05-08	2049-05-01	2019-05-08	2049-05-01	375,000,000	14,437,500	4.23
2019-08-12	2049-08-01	2019-08-12	2049-08-01	400,000,000	12,800,000	4.24
2020-01-09	2030-01-15	2020-01-09	2030-01-15	300,000,000	7,350,000	4.25
2020-01-09	2050-01-01	2020-01-09	2050-01-01	300,000,000	9,450,000	4.26
2020-05-08	2050-05-01	2020-05-08	2050-05-01	375,000,000	10,125,000	4.27
2020-08-06	2050-08-01	2020-08-06	2050-08-01	375,000,000	7,687,500	4.28
				16,115,000,700	636,871,422	33

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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

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.
In column (a), for new issues, give Commission authorization numbers and dates.
For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
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.
For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
In column (b) show the principal amount of bonds or other long-term debt originally issued.
In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
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.
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)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)
1	Bonds (Account 221)						
2	Public Service Electric and Gas Company						
3	First and Refunding Mortgage Bonds						
4.29	0.95% 2026		450,000,000		2,931,899	—	990,000
4.30	3.00% 2051		450,000,000		4,056,899	—	441,000
4.31	1.90% 2031		425,000,000		3,105,418	—	1,037,000
4.32	3.10% 2032		500,000,000		4,089,652	—	940,000
4.33	4.90% 2032		400,000,000		3,065,650	—	260,000
4.34	4.65% 2033		500,000,000		3,805,150	—	465,000
4.35	5.125% 2053		400,000,000		3,697,650	—	236,000
4.36	5.20% 2033		500,000,000		3,700,100	—	650,000
4.37	5.45% 2053		400,000,000		3,581,580	—	992,000
4.38	5.20% 2034		450,000,000		3,457,670	—	139,500
4.39	5.45% 2054		550,000,000		5,007,430	—	3,300,000
4.40	4.85% 2034		600,000,000		4,440,060	—	1,686,000
4.41	5.30% 2054		500,000,000		4,456,300	—	2,305,000
4.42	5.05% 2035		400,000,000		3,163,490	—	808,000
4.43	5.50% 2055		500,000,000		4,670,300	—	3,560,000
4.44	4.90% 2035		450,000,000		3,528,645	—	144,000
5	Subtotal		**16,468,500,00**		136,697,064	—	53,040,000
6	Reacquired Bonds (Account 222)						
7	None						
8				—			
9							
10	Subtotal		—		—	—	—
11	Advances from Associated Companies						
12	None						
13							
14							
15	Subtotal		—		—	—	—
16	Other Long Term Debt (Account 224)						
17	None						
18							
19							
20	Subtotal		—		—	—	—
33	TOTAL		16,468,500,00				

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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

Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
In a footnote, give explanatory (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) principle repaid during year. Give Commission authorization numbers and dates.
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.
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.
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.
Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)	Line No.
						1
						2
						3
2021-03-04	2026-03-15	2021-03-04	2026-03-15	450,000,000	4,275,000	4.29
2021-03-04	2051-03-01	2021-03-04	2051-03-01	450,000,000	13,500,000	4.30
2021-08-19	2031-08-15	2021-08-19	2031-08-15	425,000,000	8,075,000	4.31
2022-03-11	2032-03-15	2022-03-11	2032-03-15	500,000,000	15,500,000	4.32
2022-12-02	2032-12-15	2022-12-02	2032-12-15	400,000,000	19,600,000	4.33
2023-03-27	2033-03-15	2023-03-27	2033-03-15	500,000,000	23,250,000	4.34
2023-03-27	2053-03-15	2023-03-27	2053-03-15	400,000,000	20,500,000	4.35
2023-08-07	2033-08-01	2023-08-07	2033-08-01	500,000,000	26,000,000	4.36
2023-08-07	2053-08-01	2023-08-07	2053-08-01	400,000,000	21,800,000	4.37
2024-03-01	2034-03-01	2024-03-01	2034-03-01	450,000,000	23,400,000	4.38
2024-03-01	2054-03-01	2024-03-01	2054-03-01	550,000,000	29,975,000	4.39
2024-08-05	2034-08-01	2024-08-05	2034-08-01	600,000,000	29,100,000	4.40
2024-08-05	2054-08-01	2024-08-05	2054-08-01	500,000,000	26,500,000	4.41
2025-03-03	2035-03-01	2025-03-03	2035-03-01	400,000,000	16,721,111	4.42
2025-03-03	2055-03-01	2025-03-03	2055-03-01	500,000,000	22,763,889	4.43
2025-08-11	2035-08-15	2025-08-11	2035-08-15	450,000,000	8,575,000	4.44
				16,115,000,700	636,871,422	5
						6
						7
						8
						9
				—	—	10
						11
						12
						13
						14
				—	—	15
						16
						17
						18
						19
				—	—	20
				16,115,000,700	636,871,422	33

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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 field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, 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)	1,745,205,714
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	See footnote	(99,504,550)
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See footnote	222,534,923
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See footnote	108,340,550
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See footnote	(1,402,901,902)
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	573,674,735
28	Show Computation of Tax:	
29	See Footnote	105,688,131
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

FOOTNOTE DATA

Schedule Page: 261 Line No.: 5 Column: b

Taxable Income Not Reported on Books	
Amort of Def Gain on Sale of Services Assets	(8,514,734)
Fed Amort of Deferred Gain on Sale of Generation Assets	(90,989,816)
Total	(99,504,550)

Schedule Page: 261 Line No.: 10 Column: b

Book Deductions Not Deducted for Return	
Federal Income Taxes	(21,770,144)
State Tax Adjustment	167,565,299
P - Qualified Transportation Fringe	2,912,076
P - Amortization of Reacquisition of Pref Stock	16,357
Unallowable Civic & Pol Contributions	2,036,907
Non-deductible Meals and Entertainment	4,172,371
Penalty Adjustment	2,834,942
Diesel Fuel Tax Credit	41,000
P - W-2 Earnings Exceeding $1,000,000	28,162,923
Uncollectible Accounts	43,122,743
Amortization of Book Loss on Reacquired Debt	3,225,429
Capitalized Interest	20,062,453
Deferred Compensation	325,602
Accrued Vacation Pay Adjustment	7,287,595
3rd Party Claims	(34,492)
Bankruptcies & Acc Prov-Rent Receivable	(274,105)
Restricted Stock - Temporary	953,871
Unallowable OPEB Amortization	(29,829,170)
Unrealized G/L on Equity Securities	(147,071)
Solar Amortization	(5,394,264)
Injuries and Damages	3,804,292
Stock Comp - Book Reversal - Capitalized	(6,539,691)
Total	222,534,923

Schedule Page: 261 Line No.: 15 Column: b

Income Recorded on Books Not Included in Return	
AFUDC Debt	(18,926,449)
AFUDC / IDC - Equity	(43,687,954)
Customer Connection Fees	29,981,273
Customer Advances	40,057,125
Deferred Gain-Include All NR	100,916,555
Total	108,340,550

FOOTNOTE DATA

Schedule Page: 261 Line No.: 20 Column: b

Deductions on Return Not Charged on Books	
Restricted Stock - Permanent	(5,394,087)
COLI	(14,524,505)
ESOP/401(k)	(7,259,555)
Dividends Received Deduction	(20,918)
Casualty Loss Deferred O&M	(6,210,040)
Material & Supplies Reserve	1,667,729
PIP - Book Reversal	74,921,148
PIP - Tax Deduction	(54,085,900)
Rate Case Deferral	(2,964,740)
RE - Lease Liability	(9,279,976)
RE - ROU Lease Asset	9,621,295
FAS 5 (ASC40) Reserve - Sales Tax	166,212
CECL Reserve	983,854
Deferred Return on CIP II	299,766
COVID Deferrals	21,254,540
Deferred Depreciation on CIP II	216,009
Clause - Deferred Fuel	143,747,890
Clause - RAC (Environmental Clean Up)	707,410
Clause - Societal Benefits Clause (AAP)	56,273,476
CEF- EC AMI	26,494,233
CEF- EV Deferral	(35,240,215)
BGS DCFC Rate Program	188,152
Legal Reserves (c)	(103,895)
Deduction for Retention Payments (c)	(66,563)
Assessment by Board of Public Utilities of the State of NJ (c)	9,936,349
CEF -- EE - FT	(100,053,005)
CEF -- EE - Repay Amort	(24,358,524)
CEF -- EE - II FT	(234,609,216)
EEE Customer Repayments	2,080,130
Excess of Allowable Depreciation	1,979,638
Line Pack Adjustment	321,705
Real Estate Taxes (nc)	(288,201)
Pension - Book Reversal	10,346,884
Pension -- Deferral	(11,239,703)
Enhanced Pension Benefit Expense	(2,825,185)
AFUDC Equity Fed FT	(42,899,158)
AFUDC Equity Fed FT - Common	634,934
Basis Diff Fed FT	(51,250,083)
Basis Diff Fed Norm	(112,742,052)
Basis Diff Fed Norm - Common	(307,721)
COR Fed Norm	(13,925,573)
COR Fed Norm - Common	(57,846)
M/L Fed FT	2,276,734
M/L Fed FT - Common	(3,036,294)
M/L Fed Norm	(819,534,966)
M/L Fed Norm - Common	9,801,032
NBNT - Topside Fed	—
Tax Repairs Fed FT	(222,435,982)
P - PT Solar ITC Orig Reversal	240,456

FOOTNOTE DATA

PT In-Service Rev - AFUDC Debt	22,326,520
PT In-Service Rev - AFUDC Debt - Common	(223,463)
PT In-Service Rev - AFUDC Equity	54,196,615
PT In-Service Rev - AFUDC Equity - Common	(647,575)
PT In-Service Rev - Cap Int	(32,408,256)
PT In-Service Rev - Cap Int - Common	(3,469)
PT In-Service Rev - CIAC	(45,587,947)
Total	(1,402,901,902)

Schedule Page: 261 Line No.: 27 Column: b

Federal Taxable Net Income	573,674,735

FOOTNOTE DATA

Schedule Page: 261 Line No.: 29 Column: b

Computation of Federal Income tax:	
Federal Tax - Ordinary Income.	573,674,735
Federal Tax - Capital Gain Income.	
Total Federal tax net Income	573,674,735
Federal Income Tax before Overaccrual and Audit Adjs.	120,471,694
Tax Credits	(521,643)
	119,950,051
Increase in Federal Income Tax Liability per Return over Accrual and Audit Adjustments	(14,261,920)
Total Federal Income Tax	105,688,131

Item 2

Respondent is a member of an affiliated group of corporations filing a consolidated return. Allocation of the group's consolidated Federal Income Tax Liability applicable to the current year is as follows:

Electric Delivery	102,073,584
Gas Delivery	3,614,548
Sub-total	105,688,132
Adjustments to current year liability (Audit Adj, RTA)	14,261,920
Adjustments to FERC only items	1,219,811
PSE&G Total (Respondent)	121,169,863
Enterprise	(43,931,085)
LIPA	14,370,144
Holdings	(3,361,842)
Resources	9,283,444
Global	(911,536)
Total Consolidated Federal Income Tax Liability	96,618,988

The consolidated tax return liability or (savings) is allocated to each member of the group on a stand-alone basis solely by reference to its respective items of income, gain, deduction and credits. In the case of a net operating loss and/or tax credits, each member shall receive the tax savings to the extent such savings can be utilized by the group.

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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.
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 (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
Include in column (g) 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.
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)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)
				Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)			
1.1	Federal Income Tax	NJ	2025	—	—	106,906,684	7,579,596	(99,327,088)
1.2				—	—	—		
2	Total Federal Tax			—	—	106,906,684	7,579,596	(99,327,088)
3.1				—	—			
3.2				—	—			
4	Total State Tax			—	—	—	—	—
5.1				—	—			
5.2				—	—			
6	Total Local Tax			—	—	—	—	—
7.1	Corporate Business Tax	NJ	2025	—	—	687,115	1,000	(9,689,774)
7.2	Corporate Business Tax	NJ	2024	(6,921)	18,682,853	—	—	18,689,774
7.3	Purta	NJ		—	10,604	—	—	—
8	Total Other Tax			(6,921)	18,693,457	687,115	1,000	9,000,000
9.1				—	—			
9.2				—	—			
10	Total Property Tax			—	—	—	—	—
11.1	Real Estate Taxes	NJ	2025	—	—	32,004,645	32,004,645	—
11.2				—	—	—		
12	Total Real Estate Tax			—	—	32,004,645	32,004,645	—
13.1	Federal Unemployment Tax	NJ	2025	—	—	126,384	338,450	220,114
13.2	Federal Unemployment Tax	NJ	2024	1,648	—	—	1,648	—
13.3	NJ Unemploy Ins. tax	NJ	2025	—	—	2,054,415	5,501,657	3,585,495
13.4	NJ Unemploy Ins. tax	NJ	2024	34,234	—	—	34,234	—
14	Total Unemployment Tax			35,882	—	2,180,799	5,875,989	3,805,609
15.1	Use Taxes	NJ	2025	3,001,952	—	—	—	127,671
15.2				—	—	—		
16	Total Sales and Use Tax			3,001,952	—	—	—	127,671
17.1				—	—			
17.2				—	—			
18	Total Income Tax			—	—	—	—	—
19.1				—	—			
19.2				—	—			
20	Total Excise Tax			—	—	—	—	—
21.1				—	—			
21.2				—	—			
22	Total Fuel Tax			—	—	—	—	—
53	TOTAL			2,597,156	20,272,011	174,113,955	416,340,758	251,395,569

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (d).
Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
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.
Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (o) 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 shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
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				Line No.
Taxes Accrued (Account 236) (j)	Prepaid Taxes (Include in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustments to Ret. Earnings (Account 439) (n)	Other (o)	
—	—	109,109,653			(2,202,969)	1.1
—						1.2
—	—	109,109,653	—	—	(2,202,969)	2
—						3.1
—						3.2
—	—	—	—	—	—	4
—						5.1
—						5.2
—	—	—	—	—	—	6
(6,921)	8,996,738	(9,404,848)			10,091,963	7.1
—	—					7.2
—	10,604	—			—	7.3
(6,921)	9,007,342	(9,404,848)	—	—	10,091,963	8
—						9.1
—						9.2
—	—	—	—	—	—	10
—	—	27,112,813			4,891,832	11.1
—						11.2
—	—	27,112,813	—	—	4,891,832	12
8,048	—	67,407			58,977	13.1
—	—					13.2
138,253	—	1,095,715			958,700	13.3
—	—					13.4
146,301	—	1,163,122	—	—	1,017,677	14
3,129,623	—	—			—	15.1
—						15.2
3,129,623	—	—	—	—	—	16
—						17.1
—						17.2
—	—	—	—	—	—	18
—						19.1
—						19.2
—	—	—	—	—	—	20
—						21.1
—						21.2
—	—	—	—	—	—	22
4,400,082	12,906,171	144,521,510	—	—	29,592,445	53

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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.
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 (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
Include in column (g) 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.
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)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)
				Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)			
23.1	Contributions Tax Act	NJ	2025	—	—	30,320,713	80,910,123	52,441,573
23.2	Contributions Tax Act	NJ	2024	322,424	—	—	322,424	—
24	Total Federal Insurance Tax			322,424	—	30,320,713	81,232,547	52,441,573
25.1	Franchise Taxes	NJ	2025	(1,121,869)	—	—	—	—
25.2	Pennsylvania Franchise Tax	PA	2025	393,070	—	—	—	—
26	Total Franchise Tax			(728,799)	—	—	—	—
27.1	Misc. Other/Rounding	NJ	2025	(27,997)	—	—	—	—
27.2				—	—	—		
28	Total Miscellaneous Other Tax			(27,997)	—	—	—	—
29.1				—	—			
29.2				—	—			
30	Total Other Federal Tax			—	—	—	—	—
31.1				—	—			
31.2				—	—			
32	Total Other State Tax			—	—	—	—	—
33.1				—	—			
33.2				—	—			
34	Total Other Property Tax			—	—	—	—	—
35.1	Energy Use Tax	NJ	2025	—	—	—	287,789,951	283,891,122
35.2		NJ	2024	—	1,578,554			1,578,554
36	Total Other Use Tax			—	1,578,554	—	287,789,951	285,469,676
37.1				—	—			
37.2				—	—			
38	Total Other Advalorem Tax			—	—	—	—	—
39.1				—	—			
39.2				—	—			
40	Total Other License and Fees Tax			—	—	—	—	—
41.1	Devlp & Health Ins. and Payroll	NJ	2025	—	—	2,013,999	1,856,415	(121,872)
41.2	Devlp & Health Ins. and Payroll	NJ	2024	615	—	—	615	—
42	Total Payroll Tax			615	—	2,013,999	1,857,030	(121,872)
43.1				—	—			
43.2				—	—			
44	Total Advalorem Tax			—	—	—	—	—
53	TOTAL			2,597,156	20,272,011	174,113,955	416,340,758	251,395,569

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (d).
Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
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.
Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (o) 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 shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
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				Line No.
Taxes Accrued (Account 236) (j)	Prepaid Taxes (Include in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustments to Ret. Earnings (Account 439) (n)	Other (o)	
1,852,163	—	16,171,045			14,149,668	23.1
—	—					23.2
1,852,163	—	16,171,045	—	—	14,149,668	24
(1,121,869)	—	—			—	25.1
393,070	—	—			—	25.2
(728,799)	—	—	—	—	—	26
(27,997)	—	—			—	27.1
—						27.2
(27,997)	—	—	—	—	—	28
—						29.1
—						29.2
—	—	—	—	—	—	30
—						31.1
—						31.2
—	—	—	—	—	—	32
—						33.1
—						33.2
—	—	—	—	—	—	34
—	3,898,829	—			—	35.1
—						35.2
—	3,898,829	—	—	—	—	36
—						37.1
—						37.2
—	—	—	—	—	—	38
—						39.1
—						39.2
—	—	—	—	—	—	40
35,712	—	369,725			1,644,274	41.1
—	—					41.2
35,712	—	369,725	—	—	1,644,274	42
—						43.1
—						43.2
—	—	—	—	—	—	44
4,400,082	12,906,171	144,521,510	—	—	29,592,445	53

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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.

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 (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.

Include in column (g) 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.

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)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)
				Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)			
45.1				—	—			
45.2				—	—			
46	Total Other Allocated Tax			—	—	—	—	—
47.1				—	—			
47.2				—	—			
48	Total Severance Tax			—	—	—	—	—
49.1				—	—			
49.2				—	—			
50	Total Penalty Tax			—	—	—	—	—
51.1				—	—			
51.2				—	—			
52	Total Other Taxes and Fees			—	—	—	—	—
53	TOTAL			2,597,156	20,272,011	174,113,955	416,340,758	251,395,569

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (d).
Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
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.
Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (o) 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 shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
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				Line No.
Taxes Accrued (Account 236) (j)	Prepaid Taxes (Include in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustments to Ret. Earnings (Account 439) (n)	Other (o)	
—						45.1
—						45.2
—	—	—	—	—	—	46
—						47.1
—						47.2
—	—	—	—	—	—	48
—						49.1
—						49.2
—	—	—	—	—	—	50
—						51.1
—						51.2
—	—	—	—	—	—	52
4,400,082	12,906,171	144,521,510	—	—	29,592,445	53

FOOTNOTE DATA

Schedule Page: 263 Line No.: 1.1 Column: o

Federal Income Tax:

G409.1	2,293,676
E409.2	(1,334,653)
G409.2	(3,161,992)
Total	(2,202,969)

Schedule Page: 263 Line No.: 23.1 Column: o

Contribution Tax Act:

G408.1	14,149,668
E408.2	—
Total	14,149,668

Schedule Page: 263 Line No.: 13.1 Column: o

Federal Unemployment Tax:

G408.1	58,977

Schedule Page: 263 Line No.: 13.3 Column: o

New Jersey Unemployment Insurance Tax:

G408.1	958,700

Schedule Page: 263 Line No.: 41.1 Column: o

New Jersey Workforce Development and Health Insurance Taxes and Payroll Taxes:

G408.1	323,492
E408.2	1,262,771
G408.2	58,011
Total	1,644,274

Schedule Page: 263 Line No.: 7.1 Column: o

FERC XBRL Taxonomy: Page 262-263 Line No. 3 Column o

Corporate Business Tax:

G409.1	2,346,122
E409.2	8,838,391
G409.2	(1,092,550)
Total	10,091,963

FOOTNOTE DATA

Schedule Page: 263 Line No.: 11.1 Column: l

Real Estate Taxes:

Electric Distribution	14,423,358
Transmission	12,689,455
Total Electric	27,112,813

Schedule Page: 263 Line No.: 11.1 Column: o

Real Estate Taxes:

G408.1	4,580,073
E408.2	311,759
Total	4,891,832

Schedule Page: 263 Line No.: 53 Column: f

FERC XBRL Taxonomy: Page 262-263 Line No. 40 Column f

Reconciliation to Total Prepaid Taxes on Line 57 to Balance Sheet:

Total	Prepaid Taxes, Line 53	20,272,011
Add:	Prepaid Lease Payments	1,132,050
	Prepaid Network Admin	3,733,532
	Prepaid Credit Facilities	592,796
	Prepaid Retention	23,438
	Prepaid Materials	962,135
Total Prepaid	Prepaid per Balance Sheet	26,715,962

Schedule Page: 263 Line No.: 53 Column: k

FERC XBRL Taxonomy: Page 262-263 Line No. 40 Column k

Reconciliation to Total Prepaid Taxes on Line 57 to Balance Sheet:

Total	Prepaid Taxes, Line 53	12,906,171
Add:	Prepaid Lease Payments	1,275,348
	Prepaid Network Admin	1,227,063
	Prepaid Credit Facilities	662,826
	Prepaid Materials	138,221
Total Prepaid	Prepaid per Balance Sheet	16,209,629

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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		Allocations to Current Year's Income		Adjustments (g)
			Account No (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%	—					
3	4%	770,050				159,603	—
4	7%	—					
5	10%	1,529,980				317,108	—
6		76,421,816		480,643		10,800,085	—
7	Rounding	3		(1)		—	1
8	TOTAL	78,721,849		480,642		11,276,796	1
9	Other (List separately and show 3%, 4%, 7% 10%						
10	Gas Utility:						
11	3%	—					
12	4%	190,453				23,253	—
13	7%	228,606				27,911	—
14	10%	5,355,327				653,837	—
15	Rounding	(3)				(2)	—
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	OTHER TOTAL	5,774,383		—		704,999	—
48	GRAND TOTAL	84,496,232		480,642		11,981,795	1

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
610,447			3
—			4
1,212,872			5
66,102,374			6
3			7
67,925,696			8
			9
			10
—			11
167,200			12
200,695			13
4,701,490			14
(1)			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
5,069,384			47
72,995,080			48

FOOTNOTE DATA

Schedule Page: 266 Line No.: 8 Column: f

Electric -- Allocation to Current Year's Income

Investment Tax Credit	476,711
Solar Amortization	10,800,085
Rounding	
Total	**11,276,796**

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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 $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits	Balance at Beginning of Year	DEBITS		Credits	Balance at End of Year
			Contra Account	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	MGP (Gas Remediation)	155,825,000	182.3 / 242	14,795,712	14,955,762	155,985,050
2		—				—
3	Environmental Remediation	3,430,179	131 / 232 / 242 / 253 / 588 / 591 / 880	584,223	1,553,806	4,399,762
4		—				—
5	Non-Current Taxes Accrued	—	186 / 283	49,637,749	49,637,746	(3)
6		—				—
7	Workers Compensation	42,303,705	182	13,036,744	12,730,278	41,997,239
8		—				—
9	Cash Overages	871,842	131 / 142 / 234	6,008,984	6,495,241	1,358,099
10		—				—
11	Pre-billings on 3rd Party work	34,421,035	101 / 134 / 143 / 186	33,556,596	27,748,359	28,612,798
12		—				—
13	Distribution Customer Advances – contra	37,126,961	186 / 236 / 253 / 421	5,761,936	6,549,901	37,914,926
14		—				—
15	Distribution Customer Advances – contra	(11,395,807)	242	10,622,147	3,807,692	(18,210,262)
16		—				—
17 18 19	Other Items	(4,974,493)	101 / 131 / 134 / 143 / 184 / 186 / 236 / 241 / 242 / 253 / 421 / 426.3 / 570 / 588	8,122,848	7,529,862	(5,567,479)
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	TOTAL	257,608,422		142,126,939	131,008,647	246,490,130

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Account 282			
2	Electric	4,197,160,177	1,258,870,405	1,004,673,235
3	Gas	1,778,982,324	723,327,744	617,614,949
4	Other (Specify)	—		
5	TOTAL (Enter Total of lines 2 thru 4)	5,976,142,501	1,982,198,149	1,622,288,184
6		—		
7		—		
8		—		
9	TOTAL Account 282 (Enter Total of lines 5 thru	5,976,142,501	1,982,198,149	1,622,288,184
10	Classification of TOTAL			
11	Federal Income Tax	4,631,157,610	1,420,906,699	1,199,610,702
12	State Income Tax	1,344,984,891	561,291,450	422,677,482
13	Local Income Tax	—		

NOTES

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

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
			1,382,607,150		1,420,006,478	4,488,756,675	2
			744,034,811		784,051,244	1,924,711,552	3
						—	4
—	—		2,126,641,961		2,204,057,722	6,413,468,227	5
						—	6
						—	7
						—	8
—	—		2,126,641,961		2,204,057,722	6,413,468,227	9
							10
			2,081,028,223		2,151,378,316	4,922,803,700	11
			45,613,739		52,679,407	1,490,664,527	12
							13

NOTES (Continued)

FOOTNOTE DATA

Schedule Page: 274 Line No.: 2 Column: b

Liberalized Depreciation and other Basis Adjustment	3,950,899,551
Accounting for Income Taxes	246,260,626
Total Electric	4,197,160,177

Schedule Page: 274 Line No.: 2 Column: c

Liberalized Depreciation and other Basis Adjustment	1,258,870,405
Accounting for Income Taxes	—
Total Electric	1,258,870,405

Schedule Page: 274 Line No.: 2 Column: d

Liberalized Depreciation and other Basis Adjustment	1,004,673,235
Accounting for Income Taxes	—
Total Electric	1,004,673,235

Schedule Page: 275 Line No.: 2 Column: h

Liberalized Depreciation and other Basis Adjustment	1,382,607,150
Accounting for Income Taxes	—
Total Electric	1,382,607,150

Schedule Page: 275 Line No.: 2 Column: j

Liberalized Depreciation and other Basis Adjustment	1,412,411,936
Accounting for Income Taxes	7,594,542
Total Electric	1,420,006,478

Schedule Page: 275 Line No.: 2 Column: k

Liberalized Depreciation and other Basis Adjustment	4,234,901,507
Accounting for Income Taxes	253,855,168
Total Electric	4,488,756,675

Schedule Page: 274 Line No.: 3 Column: b

Liberalized Depreciation and other Basis Adjustment	1,708,687,736
Accounting for Income Taxes	70,294,588
Total Gas	1,778,982,324

FOOTNOTE DATA

Schedule Page: 274 Line No.: 3 Column: c

Liberalized Depreciation and other Basis Adjustment	723,327,744
Accounting for Income Taxes	—
Total Gas	723,327,744

Schedule Page: 274 Line No.: 3 Column: d

Liberalized Depreciation and other Basis Adjustment	617,614,949
Accounting for Income Taxes	—
Total Gas	617,614,949

Schedule Page: 275 Line No.: 3 Column: h

Liberalized Depreciation and other Basis Adjustment	744,034,811
Accounting for Income Taxes	—
Total Gas	744,034,811

Schedule Page: 275 Line No.: 3 Column: j

Liberalized Depreciation and other Basis Adjustment	784,146,296
Accounting for Income Taxes	(95,052)
Total Gas	784,051,244

Schedule Page: 275 Line No.: 3 Column: k

Liberalized Depreciation and other Basis Adjustment	1,854,512,016
Accounting for Income Taxes	70,199,536
Total Gas	1,924,711,552

Note:

Future rate making filings on which customer rates are determined in whole or in part based on a future period (e.g. forecasted ADIT balances) will be computed in accordance with the rules set forth in IRC regulation section 1.167(l)-1(h)(6).

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 income and deductions.

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	Account 283			
2	Electric			
3	Electric Trans and Distribution	792,518,864	72,937,047	81,231,579
4		—		
5		—		
6		—		
7		—		
8		—		
9	TOTAL Electric (Total of lines 3 thru 8)	792,518,864	72,937,047	81,231,579
10	Gas			
11	Gas Distribution	366,001,614	13,147,855	49,069,919
12		—		
13		—		
14		—		
15		—		
16		—		
17	TOTAL Gas (Total of lines 11 thru 16)	366,001,614	13,147,855	49,069,919
18	TOTAL Other	—		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	1,158,520,478	86,084,902	130,301,498
20	Classification of TOTAL			
21	Federal Income Tax	939,373,369	45,951,420	96,674,492
22	State Income Tax	219,147,109	40,133,482	33,627,006
23	Local Income Tax	—		

NOTES

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

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		CHANGES DURING YEAR					
		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)	Balance at End of Year (k)	Line No.
							1
							2
1,481,188	381,496		2,214,831		232,497,471	1,015,606,664	3
							4
							5
							6
							7
							8
1,481,188	381,496		2,214,831		232,497,471	1,015,606,664	9
							10
160,387	56,836		1,281,482		81,622,182	410,523,801	11
							12
							13
							14
							15
							16
160,387	56,836		1,281,482		81,622,182	410,523,801	17
							18
1,641,575	438,332		3,496,313		314,119,653	1,426,130,465	19
							20
1,641,575	438,332		3,348,416		312,387,762	1,198,892,886	21
—	—		147,897		1,731,891	227,237,579	22
							23

NOTES (Continued)

FOOTNOTE DATA

Schedule Page: 276 Line No.: 3 Column: b

New Jersey Corporation Business Tax	154,766,786
Accelerated Activity Plan	60,489,737
Pension	118,042,976
Loss on Reacquired Debt	1,192,097
GPRC-CEF-EE	183,528,870
Other	105,396,318
Accounting for Income Tax	169,102,080
Total Electric	792,518,864

Schedule Page: 276 Line No.: 3 Column: c

New Jersey Corporation Business Tax	33,667,675
Accelerated Activity Plan	—
Pension	1,533,407
Loss on Reacquired Debt	—
GPRC-CEF-EE	7,400,445
Other	30,335,520
Accounting for Income Tax	—
Total Electric	72,937,047

Schedule Page: 276 Line No.: 3 Column: d

New Jersey Corporation Business Tax	20,983,425
Accelerated Activity Plan	1,323,800
Pension	885,961
Loss on Reacquired Debt	470,843
GPRC-CEF-EE	5,776,107
Other	51,791,443
Accounting for Income Tax	—
Total Electric	81,231,579

Schedule Page: 276 Line No.: 11 Column: b

New Jersey Corporation Business Tax	64,380,322
Accelerated Activity Plan	42,098,460
Pension	81,447,302
Loss on Reacquired Debt	2,671,057
GPRC-CEF-EE	30,886,553
Other	63,506,771
Accounting for Income Tax	81,011,149
Total Gas	366,001,614

FOOTNOTE DATA

Schedule Page: 276 Line No.: 11 Column: c

New Jersey Corporation Business Tax	6,465,807
Accelerated Activity Plan	—
Pension	1,420,219
Loss on Reacquired Debt	—
GPRC-CEF-EE	—
Other	5,261,829
Accounting for Income Tax	—
Total Gas	13,147,855

Schedule Page: 276 Line No.: 11 Column: d

New Jersey Corporation Business Tax	12,643,581
Accelerated Activity Plan	10,063,838
Pension	1,286,884
Loss on Reacquired Debt	206,497
GPRC-CEF-EE	217,473
Other	24,651,646
Accounting for Income Tax	—
Total Gas	49,069,919

Schedule Page: 277 Line No.: 3 Column: e

New Jersey Corporation Business Tax	11,441
Accelerated Activity Plan	—
Pension	—
Loss on Reacquired Debt	—
Other	1,469,747
Accounting for Income Tax	—
Total Electric	1,481,188

Schedule Page: 277 Line No.: 3 Column: f

New Jersey Corporation Business Tax	45,179
Accelerated Activity Plan	—
Pension	—
Loss on Reacquired Debt	—
GPRC-CEF-EE	—
Other	336,317
Accounting for Income Tax	—
Total Electric	381,496

FOOTNOTE DATA

Schedule Page: 277 Line No.: 3 Column: h

New Jersey Corporation Business Tax	109,626
Accelerated Activity Plan	323,790
Pension	—
Loss on Reacquired Debt	—
GPRC-CEF-EE	—
Other	1,611,943
Accounting for Income Tax	169,472
Total Electric	2,214,831

Schedule Page: 277 Line No.: 3 Column: j

New Jersey Corporation Business Tax	1,351,161
Accelerated Activity Plan	—
Pension	—
Loss on Reacquired Debt	—
GPRC-CEF-EE	61,085,002
Other	(938,800)
Accounting for Income Tax	171,000,108
Total Electric	232,497,471

Schedule Page: 277 Line No.: 3 Column: k

New Jersey Corporation Business Tax	168,658,832
Accelerated Activity Plan	58,842,147
Pension	118,690,422
Loss on Reacquired Debt	721,254
GPRC-CEF-EE	246,238,211
Other	82,523,082
Accounting for Income Tax	339,932,716
Total Electric	1,015,606,664

Schedule Page: 277 Line No.: 11 Column: e

New Jersey Corporation Business Tax	20,323
Other	140,064
Accounting for Income Tax	—
Total Gas	160,387

Schedule Page: 277 Line No.: 11 Column: f

New Jersey Corporation Business Tax	5,140
Other	51,696
Accounting for Income Tax	—
Total Gas	56,836

FOOTNOTE DATA

Schedule Page: 277 Line No.: 11 Column: h

New Jersey Corporation Business Tax	38,271
Accelerated Activity Plan	113,038
Pension	—
Loss on Reacquired Debt	—
GPRC-CEF-EE	662,480
Other	408,529
Accounting for Income Tax	59,164
Total Gas	1,281,482

Schedule Page: 277 Line No.: 11 Column: j

New Jersey Corporation Business Tax	380,730
Accelerated Activity Plan	—
Pension	—
Loss on Reacquired Debt	—
GPRC-CEF-EE	14,708,358
Other	1,030,024
Accounting for Income Tax	65,503,070
Total Gas	81,622,182

Schedule Page: 277 Line No.: 11 Column: k

New Jersey Corporation Business Tax	58,560,190
Accelerated Activity Plan	31,921,584
Pension	81,580,636
Loss on Reacquired Debt	2,464,560
GPRC-CEF-EE	44,714,959
Other	44,826,817
Accounting for Income Tax	146,455,055
Total Gas	410,523,801

Note:
Future rate making filings on which customer rates are determined in whole or in part based on a future period (e.g. forecasted ADIT balances) will be computed in accordance with the rules set forth in IRC regulation section 1.167(l)-1(h)(6).

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Beginning of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	**Distribution specific regulatory liabilities resulting from approved NJBPU rate mechanisms:**	—				—
2	Zero Emission Credits (ZEC's)	6,693,039	254, 955	1,119,819	97,050	5,670,270
3	Green Programs Recovery Clause (GPRC)	8,417,516	182.3, 254, 431, 456, 908	107,262,395	98,844,879	—
4	Solar Pilot Recovery Charge (SPRC)	798,241	182, 254, 124	1,625,479	827,238	—
5	Tax Adjustment Credit (TAC)	—	Various	25,833,333	79,812,954	53,979,621
6	Gas Margin Adjustment Charge (G-MAC)	17,333,974	Various	—	2,936,728	20,270,702
7	Conservation Incentive Program (CIP - GD)		254	—	12,350,690	12,350,690
8	**Electric & Gas default energy supply to distribution customers recovered/ returned to customers under approved NJBPU recovery mechanisms**	—	—	—	—	—
9	Underrecovered Electric Costs (BGS)	—	182, 955	3,542,882	3,542,882	—
10	Deferred Gas Fuel Costs (BGSS-R)	144,822,991	182, 254, 804	27,267,844	—	117,555,147
11	Non-Utility Generation Charge (NGC)	2,681,698	—	—	24,992	2,706,690
12	**Distribution specific regulatory liabilities recorded as a result of the NJBPU 2024 Distribution Base Rate Case Order:**	—	—	—	—	—
13	Recovery of Other Electric Non-Major Storm Costs	2,873,396	182, 254, 908	15,073,396	12,200,000	—
14	**Transmission Formula Rate regulatory liability:**	—	—	—	—	—
15	Transmission Formula Rate True Ups	(1)	182, 254, 495	—	—	(1)
16	**Regulatory liabilities to be returned in future rates:**	—	—	—	—	—
17	Deferred Income Tax Regulatory Liability	249,382,455	Various	28,983,571	56,666,827	277,065,711
18	Excess Accumulated Deferred Income Tax Liabilities	2,587,309,364	Various	451,304,164	121,046,686	2,257,051,886
19	Gas Forward Contract Purchase	23,684,439	182, 254	23,684,439	—	—
20		—				—
21		—				—
22		—				—
23		—				—
24		—				—
25		—				—
26		—				—
27		—				—
28		—				—
29		—				—
30		—				—
31		—				—
32		—				—
33		—				—
34		—				—
35		—				—
36		—				—
37		—				—
41	TOTAL	3,043,997,112		685,697,322	388,350,926	2,746,650,716

FOOTNOTE DATA

Schedule Page: 278 Line No.: 18 Column: b

FERC Form 1 - December 31, 2025
Analysis Of Deferred Income Tax Regulatory Liability - Account 254

These amounts represent the future refunds to customers of PSE&G's excess accumulated deferred income tax liabilities as a result of the reduction in the federal corporate income tax rate effective January 1, 2018 and the flowback of tax repair related accumulated deferred income taxes that PSE&G agreed to as part of the settlement of its 2018 distribution base rate proceeding and FERC approved PSE&G Section 205 filing.

The amount of excess deferred income taxes that is considered protected and unprotected as of December 31, 2024 and 2025 is reflected below (in millions):

12/31/2024 Balance

	Electric Distribution	Gas Distribution	Transmission	Total
Protected Plant Related	460,317,449	379,848,990	928,283,608	1,768,450,047
Historic SHARE	96,809,383	213,067,000	—	309,876,383
Historic Mixed Services	265,266,050	243,716,884	—	508,982,934
Total	822,392,882	836,632,874	928,283,608	2,587,309,364

FERC Form 1 - 12/31/2024
Deferred Income Tax Expense/(Benefit) - Regulatory Account 411.1

	Electric Distribution	Gas Distribution	Transmission	Total
Protected Plant Related	(10,405,684)	(5,092,902)	(1,657,414)	(17,156,000)
Unprotected Plant Related	(7,569,160)	(6,978,488)	—	(14,547,648)
Historic SHARE	(17,399,067)	(38,293,467)	—	(55,692,534)
Total	(35,373,911)	(50,364,857)	(1,657,414)	(87,396,182)

Schedule Page:278 Line No:27 Column d-e

FERC Form 1 - 12/31/2025
Net Activity for 2025 Year

	Electric Distribution	Gas Distribution	Transmission	Total
Protected Plant Related	(22,097,672)	(6,975,812)	(2,236,362)	(31,309,846)
Historic SHARE	(24,202,192)	(53,266,625)	—	(77,468,817)
Historic Mixed Services	(115,344,622)	(128,000,106)	—	(243,344,728)
Hist Mixed Service Cost	12,942,387	8,923,526		21,865,913
Total	(148,702,099)	(179,319,017)	(2,236,362)	(330,257,478)

FOOTNOTE DATA

Schedule Page:278 Line No:27 Column f

12/31/2025 Balance

	Electric Distribution	Gas Distribution	Transmission	Total
Protected Plant Related	438,219,777	372,873,178	926,047,246	1,737,140,201
Historic SHARE	72,607,191	159,800,375	—	232,407,566
Historic Mixed Services	149,921,428	115,716,778	—	265,638,206
Hist Mixed Service Cost	12,942,387	8,923,526		21,865,913
Total	673,690,783	657,313,857	926,047,246	2,257,051,886

FERC Form 1 - 12/31/2025
Deferred Income Tax Expense/(Benefit) - Regulatory Account 411.1

	Electric Distribution	Gas Distribution	Transmission	Total
Protected Plant Related	(15,886,016)	(5,014,912)	(1,607,721)	(22,508,649)
Historic SHARE	(17,398,956)	(38,293,377)	—	(55,692,333)
Historic Mixed Services	(82,921,249)	(92,019,276)		(174,940,525)
Hist Mixed Service Cost	9,304,282	6,415,123		15,719,405
Total	(106,901,939)	(128,912,442)	(1,607,721)	(237,422,102)

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. 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.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	3,368,322,127	2,754,538,309
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	2,363,761,075	2,068,052,105
5	Large (or Ind.) (See Instr. 4)	266,689,968	227,736,158
6	(444) Public Street and Highway Lighting	91,114,019	84,545,647
7	(445) Other Sales to Public Authorities		—
8	(446) Sales to Railroads and Railways		—
9	(448) Interdepartmental Sales	1,464,309	1,276,090
10	TOTAL Sales to Ultimate Consumers	6,091,351,498	5,136,148,309
11	(447) Sales for Resale	13,465,930	6,741,180
12	TOTAL Sales of Electricity	6,104,817,428	5,142,889,489
13	(Less) (449.1) Provision for Rate Refunds	—	—
14	TOTAL Revenues Net of Prov. for Refunds	6,104,817,428	5,142,889,489
15	Other Operating Revenues		
16	(450) Forfeited Discounts	4,841,247	4,210,229
17	(451) Miscellaneous Service Revenues	30,232,379	36,697,497
18	(453) Sales of Water and Water Power		—
19	(454) Rent from Electric Property	14,056,772	11,648,245
20	(455) Interdepartmental Rents		—
21	(456) Other Electric Revenues	(115,832,530)	39,011,213
22	(456.1) Revenues from Transmission of Electricity of Others	721,317,502	692,002,908
23	(457.1) Regional Control Service Revenues		—
24	(457.2) Miscellaneous Revenues		—
25			—
26	TOTAL Other Operating Revenues	654,615,370	783,570,092
27	TOTAL Electric Operating Revenues	6,759,432,798	5,926,459,581

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. 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.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
13,891,076	13,907,144	2,073,707	2,056,231	2
				3
22,680,817	22,725,850	315,578	314,205	4
3,653,424	3,689,099	8,218	8,379	5
335,633	329,245	11,154	10,950	6
	—		—	7
	—		—	8
7,370	7,370	466	460	9
40,568,320	40,658,708	2,409,123	2,390,225	10
140,476	141,305		—	11
40,708,796	40,800,013	2,409,123	2,390,225	12
	—		—	13
40,708,796	40,800,013	2,409,123	2,390,225	14
Line 12, column (b) includes	36,482,266	of unbilled revenues.		
Line 12, column (d) includes	88,597	MWH relating to unbilled revenues		

FOOTNOTE DATA

Schedule Page: 300 Line No.: 11 Column: c

Account (447) differs from page 397 because it includes other transmission revenue. Page 397 excludes other transmission revenues. Those revenues are unbundled and are shown as a separate line item on page 397.

Schedule Page: 300 Line No.: 17 Column: b

Account (451) Miscellaneous Service Revenue - Amount greater than $250,000

ASB Service Contract Revenue	$	21,279,797
Sundry Sales Revenue from Service Reconnect	$	1,996,560

*Pursuant to approval by NJ BPU in Docket Nos. ER18010029 and GR18010030 in PSE&G's electric and gas base rate cases respectively, PSE&G began offering appliance service repairs to electric customers with the full year results reflected as of December 31, 2024.

Schedule Page: 300 Line No.: 17 Column: c

Account (451) Miscellaneous Service Revenue - Amount greater than $250,000

ASB Service Contract Revenue	$	31,868,790
Sundry Sales Revenue from Service Reconnect	$	4,794,975

*Pursuant to approval by NJ BPU in Docket Nos. ER18010029 and GR18010030 in PSE&G's electric and gas base rate cases respectively, PSE&G began offering appliance service repairs to electric customers with the full year results reflected as of December 31, 2024.

Schedule Page: 300 Line No.: 21 Column: b

Account (456) Other Electric Revenue- Amounts greater $250,000

Electric CIP Decoupling Revenues and Amortization	$	(81,141,243)
Electric Tax Adjustment Clause Over/Under		(49,774,005)
Trans-interconnection agreement		8,364,060
Transmission ancillary charges		4,717,395
Other ED Revenues		1,740,829
Clean Energy Future - EE		81,858

Schedule Page: 300 Line No.: 21 Column: c

Account (456) Other Electric Revenue- Amounts greater $250,000

Electric CIP Decoupling Revenues and Amortization	11,049,656
Electric Tax Adjustment Clause Over/Under	12,557,995
Trans-interconnection agreement-	8,271,576
Transmission ancillary charges-	4,719,902
Other ED Revenues	2,151,733
Clean Energy Future - EE	95,576

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rates schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date 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," Page 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 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 the 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)
	Residential Sales					
1	Residential Service (RS)	13,586,241	3,282,449,746	2,056,209	6607	0.2416
2	Residential Heating Service (RHS)	73,623	13,423,548	5,905	12,468	0.1823
2.1	Residential Load Management Service (RLM)	183,387	42,638,472	11,591	15,821	0.2325
2.2	Water Heating (WH)	166	26,477			0.1595
2.3	Water Heating Storage (WHS)	5	527			0.1054
3	Residential Sales Billed	13,843,426	3,338,541,638	2,073,707	6,676	0.2412
4	Residential Sales Unbilled	47,650	29,780,489			0.6250
5	Residential Sales Total	13,891,076	3,368,322,127	2,073,707	6,699	0.2425
	Commercial Sales					
6	Building Heating Service (HS)	9,296	1,651,795	643	14,457	0.1777
7	General Lighting and Power Service (GLP)	7,198,732	1,161,394,945	281,596	25,564	0.1613
7.1	Large Power and Light Primary Service (LPLP)	2,380,697	149,329,066	605	3,935,036	0.0627
7.2	Large Power and Light Secondary Service (LPLS)	9,271,525	863,098,618	9,029	1,026,861	0.0931
7.3	High Tension Service Subtransmission (HTS-SUB)	3,237,296	135,785,091	105	30,831,390	0.0419
7.4	High Tension Service High Voltage (HTS-HV)	442,795	9,229,104	12	36,899,583	0.0208
7.5	Private Street and Area Lighting Service (PSAL)	128,922	40,150,759	23,588	5,466	0.3114
7.6	Water Heating (WH)	7	884			0.1263
8	Commercial Sales Billed	22,669,270	2,360,640,262	315,578	71,834	0.1041
9	Commercial Sales Unbilled	11,547	3,120,813			0.2703
10	Commercial Sales Total	22,680,817	2,363,761,075	315,578	71,871	0.1042
	Industrial Sales					
11	Building Heating Service (HS)	269	57,549	25	10,760	0.2139
12	General Lighting and Power Service (GLP)	270,976	46,648,411	7,051	38,431	0.1721
12.1	Large Power and Light Primary Service (LPLP)	643,846	36,582,316	200	3,219,230	0.0568
12.2	Large Power and Light Secondary Service (LPLS)	1,035,201	91,426,643	845	1,225,090	0.0883
12.3	High Tension Service Subtransmission (HTS-SUB)	1,546,741	80,760,579	90	17,186,011	0.0522
12.4	High Tension Service High Voltage (HTS-HV)	126,992	7,633,505	7	18,141,714	0.0601
13	Industrial Sales Billed	3,624,025	263,109,003	8,218	440,986	0.0726
14	Industrial Sales Unbilled	29,399	3,580,965			0.1218
15	Industrial Sales Total	3,653,424	266,689,968	8,218	444,564	0.0730
	Total Sales					
46	TOTAL Billed	40,479,724	6,054,869,231	2,409,123	565,402	0.1496
47	Total Unbilled Rev.(See Instr. 6)	88,596	36,482,267	—	—	0.4118
48	TOTAL	40,568,320	6,091,351,498	2,409,123	565,402	0.1502

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rates schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date 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," Page 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 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 the 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)
	Public Street and Highway Lighting Sales					
21	Body Politic Lighting Service (BPL)	287,029	85,000,242	5,267	54,496	0.2961
22	Body Politic Lighting Service from Publicly Owned Facilities (BPL-POF)	14,024	1,682,493	92	152,435	0.1200
22.1	General Lighting and Power Service (GLP)	34,580	4,431,284	5,795	5,967	0.1281
23	Public Street and Highway Lighting Sales Billed	335,633	91,114,019	11,154	30,091	0.2715
24	Public Street and Highway Lighting Sales Unbilled	—	—			
25	Public Street and Highway Lighting Sales Total	335,633	91,114,019	11,154	30,091	0.2715
	Other Sales to Public Authorities					
26						
27						
28	Other Sales to Public Authorities Billed					
29	Other Sales to Public Authorities Unbilled					
30	Other Sales to Public Authorities Total					
	Sales to Railroads and Railways					
31						
32						
33	Sales to Railroads and Railways Billed					
34	Sales to Railroads and Railways Unbilled					
35	Sales to Railroads and Railways Total					
	Interdepartmental Sales					
36	Interdepartmental	7,370	1,464,309	466	15,815	0.1987
37						
38	Interdepartmental Sales Billed	7,370	1,464,309	466	15,815	0.1987
39	Interdepartmental Sales Unbilled	—	—	—		
40	Interdepartmental Sales Total	7,370	1,464,309	466	15,815	0.1987
	Provision for Rate Refunds					
41						
42						
43	Provision for Rate Refunds Billed					
44	Provision for Rate Refunds Unbilled					
45	Provision for Rate Refunds Total					
	Total Sales					
46	TOTAL Billed	40,479,724	6,054,869,231	2,409,123	565,402	0.1496
47	Total Unbilled Rev.(See Instr. 6)	88,596	36,482,267	—	—	0.4118
48	TOTAL	40,568,320	6,091,351,498	2,409,123	565,402	0.1502

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 tong-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 setter 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 designated 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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	PJM					
2	Solar-4-All	SF	1st Rev. Vol 6			
3	Energy Efficiency	SF	1st Rev. Vol 6			
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15	Subtotal RQ			—	—	—
16	Subtotal non-RQ			—	—	—
17	**Total**			—	—	—

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 (9) 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 megawatt hours 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 subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled 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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold	REVENUE			Total ($) (h+i+j)	Line No.
	Demand Charges ($)	Energy Charges ($)	Other Charges ($)		
(g)	(h)	(i)	(j)	(k)	
				—	1
140,476	—	6,239,435		6,239,435	2
	7,226,495	—		7,226,495	3
				—	4
				—	5
				—	6
				—	7
				—	8
				—	9
				—	10
				—	11
				—	12
				—	13
				—	14
—	—	—	—	—	15
140,476	7,226,495	6,239,435	—	13,465,930	16
140,476	7,226,495	6,239,435	—	13,465,930	17

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

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	—	—
5	(501) Fuel	—	—
6	(502) Steam Expenses	—	—
7	(503) Steam from Other Sources	—	—
8	(Less) (504) Steam Transferred-Cr.	—	—
9	(505) Electric Expenses	—	—
10	(506) Miscellaneous Steam Power Expenses	—	—
11	(507) Rents	—	—
12	(509) Allowances	—	—
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	—	—
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	—	—
16	(511) Maintenance of Structures	—	—
17	(512) Maintenance of Boiler Plant	—	—
18	(513) Maintenance of Electric Plant	—	—
18.1	(513.1) Maintenance of Computer Hardware		—
18.2	(513.2) Maintenance of Computer Software		—
18.3	(513.3) Maintenance of Communication Equipment		—
19	(514) Maintenance of Miscellaneous Steam Plant	—	—
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	—	—
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	—	—
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	—	—
25	(518) Fuel	—	—
26	(519) Coolants and Water	—	—
27	(520) Steam Expenses	—	—
28	(521) Steam from Other Sources	—	—
29	(Less) (522) Steam Transferred-Cr.	—	—
30	(523) Electric Expenses	—	—
31	(524) Miscellaneous Nuclear Power Expenses	—	—
32	(525) Rents	—	—
33	TOTAL Operation (Enter Total of lines 24 thru 32)	—	—
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	—	—
36	(529) Maintenance of Structures	—	—
37	(530) Maintenance of Reactor Plant Equipment	—	—
38	(531) Maintenance of Electric Plant	—	—
38.1	(531.1) Maintenance of Computer Hardware		—
38.2	(531.2) Maintenance of Computer Software		—
38.3	(531.3) Maintenance of Communication Equipment		—
39	(532) Maintenance of Miscellaneous Nuclear Plant	—	—
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	—	—
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	—	—
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	—	—
45	(536) Water for Power	—	—
46	(537) Hydraulic Expenses	—	—
47	(538) Electric Expenses	—	—
48	(539) Miscellaneous Hydraulic Power Generation Expenses	—	—
49	(540) Rents	—	—
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	—	—
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	—	—

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	**Amount for Current Year (b)**	**Amount for Previous Year (c)**
54	(542) Maintenance of Structures	—	—
55	(543) Maintenance of Reservoirs, Dams, and Waterways	—	—
56	(544) Maintenance of Electric Plant	—	—
56.1	(544.1) Maintenance of Computer Hardware		—
56.2	(544.2) Maintenance of Computer Software		—
56.3	(544.3) Maintenance of Communication Equipment		—
57	(545) Maintenance of Miscellaneous Hydraulic Plant	—	—
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	—	—
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	—	—

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	—	—
63	(547) Fuel	—	—
64	(548) Generation Expenses	—	—
65	(549) Miscellaneous Other Power Generation Expenses	—	—
66	(550) Rents	—	—
67	TOTAL Operation (Enter Total of lines 62 thru 66)	—	—
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	—	—
70	(552) Maintenance of Structures	—	—
71	(553) Maintenance of Generating and Electric Plant	—	—
71.1	(553.1) Maintenance of Computer Hardware		—
71.2	(553.2) Maintenance of Computer Software		—
71.3	(553.3) Maintenance of Communication Equipment		—
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	—	—
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	—	—
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	—	—
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	2,700,046,465	2,239,551,850
76.1	(555.1) Power Purchased for Storage Operations	—	—
76.2	(555.2) Bundled Environmental Credits		—
76.3	(555.3) Unbundled Environmental Credits		—
77	(556) System Control and Load Dispatching	279,144	180,861
78	(557) Other Expenses	—	—
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	2,700,325,609	2,239,732,711
79.1	F. Solar Generation		
79.2	Operation		
79.3	(558.1) Operation Supervision and Engineering		—
79.4	(558.2) Solar Panel Generation and Other Plant Operating Expenses		—
79.6	(558.4) Rents		—
79.7	TOTAL Operation (Enter Total of lines 79.3 thru 79.6)	—	—
79.8	Maintenance		
79.9	(558.6) Maintenance Supervision and Engineering		—
79.10	(558.7) Maintenance of Solar Panels, Structures, and Equipment		—
79.11	(558.8) Maintenance of Computer Hardware		—
79.12	(558.9) Maintenance of Computer Software		—
79.13	(558.10) Maintenance of Communication Equipment		—
79.14	(558.11) Maintenance of Miscellaneous Solar Generation Plant		—
79.15	TOTAL Maintenance (Enter Total of lines 79.9 thru 79.14)	—	—
79.16	TOTAL Power Production Expenses-Solar (total of lines 79.7 & 79.15)	—	—
79.17	G. Wind Generation		
79.18	Operation		
79.19	(558.13) Operation Supervision and Engineering		—
79.20	(558.14) Wind Turbine Generation and Other Plant Operating Expenses		—
79.21	(558.16) Rents		—
79.22	TOTAL Operation (Enter Total of lines 79.19 thru 79.21)	—	—
79.23	Maintenance		
79.24	(558.18) Maintenance Supervision and Engineering		—
79.25	(558.19) Maintenance of Wind Turbines, Structures, and Equipment		—
79.26	(558.20) Maintenance of Computer Hardware		—
79.27	(558.21) Maintenance of Computer Software		—
79.28	(558.22) Maintenance of Communication Equipment		—
79.29	(558.23) Maintenance of Miscellaneous Wind Generation Plant		—
79.30	TOTAL Maintenance (Enter Total of lines 79.24 thru 79.29)	—	—
79.31	TOTAL Power Production Expenses-Wind (total of lines 79.22 & 79.30)	—	—

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
79.32	H. Other Renewable Generation		
79.33	Operation		
79.34	(559.1) Operation Supervision and Engineering		—
79.35	(559.2) Other Miscellaneous Generation and Other Plant Operating Expenses		—
79.36	(559.3) Fuel		—
79.37	(559.4) Rents		—
79.38	TOTAL Operation (Enter Total of lines 79.34 thru 79.37)	—	—
79.39	Maintenance		
79.40	(559.6) Maintenance Supervision and Engineering		—
79.41	(559.7) Maintenance of Structures		—
79.42	(559.9) Maintenance of Boilers		—
79.43	(559.10) Maintenance of Generating and Electric Equipment		—
79.44	(559.12) Maintenance of Computer Hardware		—
79.45	(559.13) Maintenance of Computer Software		—
79.46	(559.14) Maintenance of Communication Equipment		—
79.47	(559.15) Maintenance of Miscellaneous Renewable Production Plant		—
79.48	TOTAL Maintenance (Enter Total of lines 79.40 thru 79.47)	—	—
79.49	TOTAL Power Production Expenses-Other Renewable (total of lines 79.38 & 79.48)	—	—
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,700,325,609	2,239,732,711
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	—	—
84			
85	(561.1) Load Dispatch-Reliability	7,244,805	7,173,872
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	4,277,870	4,289,661
87	(561.3) Load Dispatch-Transmission Service and Scheduling	—	—
88	(561.4) Scheduling, System Control and Dispatch Services	—	—
89	(561.5) Reliability, Planning and Standards Development	10,237,291	8,514,624
90	(561.6) Transmission Service Studies	—	—
91	(561.7) Generation Interconnection Studies	—	—
92	(561.8) Reliability, Planning and Standards Development Services	—	—
93	(562) Station Expenses	3,852,160	6,060,008
94	(563) Overhead Lines Expenses	11,261,934	10,102,569
95	(564) Underground Lines Expenses	9,548,405	7,399,055
96	(565) Transmission of Electricity by Others	—	—
97	(566) Miscellaneous Transmission Expenses	13,669,916	15,584,866
98	(567) Rents	6,567,139	4,275,582
99	TOTAL Operation (Enter Total of lines 83 thru 98)	66,659,520	63,400,237
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	—	—
102	(569) Maintenance of Structures	9,661,799	7,642,868
103	(569.1) Maintenance of Computer Hardware	4,420,228	4,446,687
104	(569.2) Maintenance of Computer Software	2,045,397	2,036,661
105	(569.3) Maintenance of Communication Equipment	1,926,875	1,369,407
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	—	—
107	(570) Maintenance of Station Equipment	30,242,346	25,276,964
108	(571) Maintenance of Overhead Lines	33,225,260	37,207,334
109	(572) Maintenance of Underground Lines	4,874,236	5,467,923
110	(573) Maintenance of Miscellaneous Transmission Plant	223,590	644,379
111	TOTAL Maintenance (Total of lines 101 thru 110)	86,619,731	84,092,223
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	153,279,251	147,492,460

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Classification (a)	**Amount for Current Year** **(b)**	**Amount for Previous Year** **(c)**
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision	—	—
116	(575.2) Day-Ahead and Real-Time Market Facilitation	—	—
117	(575.3) Transmission Rights Market Facilitation	—	—
118	(575.4) Capacity Market Facilitation	—	—
119	(575.5) Ancillary Services Market Facilitation	—	—
120	(575.6) Market Monitoring and Compliance	—	—
121	(575.7) Market Facilitation, Monitoring and Compliance Services	—	—
122	(575.8) Rents	—	—
123	Total Operation (Lines 115 thru 122)	—	—
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements	—	—
126	(576.2) Maintenance of Computer Hardware	—	—
127	(576.3) Maintenance of Computer Software	—	—
128	(576.4) Maintenance of Communication Equipment	—	—
129	(576.5) Maintenance of Miscellaneous Market Operation Plant	—	—
130	Total Maintenance (Lines 125 thru 129)	—	—
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	—	—
131.1	4. ENERGY STORAGE EXPENSES		
131.2	Operation		
131.3	(577.1) Operation Supervision and Engineering		—
131.4	(577.2) Operation of Energy Storage Equipment		—
131.5	(577.3) Storage Fuel		—
131.6	(577.4) Rents		—
131.7	Total Operation (Lines 131.3 thru 131.6)	—	—
131.8	Maintenance		
131.9	(578.1) Maintenance Supervision and Engineering		—
131.10	(578.2) Maintenance of Energy Storage Equipment and Structures		—
131.11	(578.3) Maintenance of Computer Hardware		—
131.12	(578.4) Maintenance of Computer Software		—
131.13	(578.5) Maintenance of Communication Equipment		—
131.14	(578.6) Maintenance of Miscellaneous Other Energy Storage Plant		—
131.15	Total Maintenance (Lines 131.9 thru 131.14)	—	—
131.16	TOTAL Energy Storage Expenses (Total of 131.7 and 131.15)	—	—
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	—	—
135	(581) Load Dispatching	—	—
136	(582) Station Expenses	2,123,972	1,423,726
137	(583) Overhead Line Expenses	4,312,050	4,364,154
138	(584) Underground Line Expenses	9,930,409	8,043,260
139	(585) Street Lighting and Signal System Expenses	5,794	—
140	(586) Meter Expenses	6,841,401	6,748,113
141	(587) Customer Installations Expenses	5,175,351	4,655,737
142	(588) Miscellaneous Expenses	50,412,709	43,035,691
143	(589) Rents	3,407,901	1,576,562
144	TOTAL Operation (Enter Total of lines 134 thru 143)	82,209,587	69,847,243
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	—	—
147	(591) Maintenance of Structures	15,846,462	15,180,729
148	(592) Maintenance of Station Equipment	17,168,945	14,930,272
148.1	(592.2) Maintenance of Computer Hardware		—
148.2	(592.3) Maintenance of Computer Software		—
148.3	(592.4) Maintenance of Communication Equipment		—

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Classification (a)	**Amount for Current Year** **(b)**	**Amount for Previous Year** **(c)**
149	(593) Maintenance of Overhead Lines	66,781,728	69,665,834
150	(594) Maintenance of Underground Lines	21,758,135	18,794,515
151	(595) Maintenance of Line Transformers	5,089,862	4,308,011
152	(596) Maintenance of Street Lighting and Signal Systems	12,959,923	10,994,219
153	(597) Maintenance of Meters	655,758	856,248
154	(598) Maintenance of Miscellaneous Distribution Plant	1,425,389	1,484,486
155	TOTAL Maintenance (Total of lines 146 thru 154)	141,686,202	136,214,314
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	223,895,789	206,061,557
157	6. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	—	—
160	(902) Meter Reading Expenses	15,914,232	15,182,505
161	(903) Customer Records and Collection Expenses	90,103,025	86,874,335
162	(904) Uncollectible Accounts	118,434,133	108,734,434
163	(905) Miscellaneous Customer Accounts Expenses	126,438,516	86,656,137
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	350,889,906	297,447,411

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Classification (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	7. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	—	—
168	(908) Customer Assistance Expenses	341,449,856	222,543,632
169	(909) Informational and Instructional Expenses	—	—
170	(910) Miscellaneous Customer Service and Informational Expenses	2,896,964	2,044,608
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	344,346,820	224,588,240
172	8. SALES EXPENSES		
173	Operation		
174	(911) Supervision	—	—
175	(912) Demonstrating and Selling Expenses	614,372	303,499
176	(913) Advertising Expenses	—	35,748
177	(916) Miscellaneous Sales Expenses	—	—
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	614,372	339,247
179	9. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	12,577,475	8,836,347
182	(921) Office Supplies and Expenses	1,449,702	1,529,024
183	(Less) (922) Administrative Expenses Transferred-Credit	—	—
184	(923) Outside Services Employed	130,415,771	128,430,418
185	(924) Property Insurance	3,141,704	3,320,339
186	(925) Injuries and Damages	22,034,044	15,491,420
187	(926) Employee Pensions and Benefits	1,512,236	1,922,122
188	(927) Franchise Requirements	—	—
189	(928) Regulatory Commission Expenses	16,176,002	14,538,095
190	(929) (Less) Duplicate Charges-Cr.	4,243,041	3,524,604
191	(930.1) General Advertising Expenses	2,433,000	2,419,897
192	(930.2) Miscellaneous General Expenses	5,907,947	5,636,893
193	(931) Rents	5,244,894	5,870,671
194	TOTAL Operation (Enter Total of lines 181 thru 193)	196,649,734	184,470,622
195	Maintenance		
196	(935) Maintenance of General Plant	—	—
196.1	(935.1) Maintenance of Computer Hardware		—
196.2	(935.2) Maintenance of Computer Software		—
196.3	(935.3) Maintenance of Communication Equipment		—
196.4	TOTAL Maintenance (Enter Total of lines 196 thru 196.3)	—	—
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196.4)	196,649,734	184,470,622
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 131.16, 156, 164, 171, 178, and 197)	3,970,001,481	3,300,132,248

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also 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 projects load for this service in its system resource planning). In addition, the reliability 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 firm service which meets the definition of RQ service. For all transaction 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.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	AXPO U.S. LLC	RQ	Sch No 1			
2	BP	RQ	Sch No 1			
3	BTG/ENGELHART	RQ	Sch No 1			
4	CALPINE ENERGY SVCS., L.P.	RQ	Sch No 1			
5	CONOCO PHILLIPS	RQ	Sch No 1			
6	DTE	RQ	Sch No 1			
7	Constellation Energy Generation LLC (Exelon Generation Company, LLC)	RQ	Sch No 1			
8	MACQUAIRE	RQ	Sch No 1			
9	NEXTERA	RQ	Sch No 1			
10	Boston Energy Trading and Marekting LLC	RQ	Sch No 1			
11	Verition Multi-Strategy Master Fund dba Five Elements Energy II LLC	RQ	Sch No 1			
12	HARTREE Partners, L.P.	RQ	Sch No 1			
13	Vitol, Inc.	RQ	Orig Vol 1			
14	BRISTOL MEYERS SQUIBB	OS	Orig Vol 1			
15	Total			—	—	—

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC 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 provided.

5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (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 columns (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 (l) 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.

MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
		MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)	
2,252,891					197,817,442		197,817,442	1
2,422,344					247,229,492		247,229,492	2
170,264					18,257,926		18,257,926	3
818,612					83,248,571		83,248,571	4
896,276					83,534,936		83,534,936	5
3,916,816					373,366,459		373,366,459	6
2,124,088					204,315,912		204,315,912	7
988,862					101,554,808		101,554,808	8
8,637,797					812,746,618		812,746,618	9
281,621					23,081,654		23,081,654	10
783,656					80,361,333		80,361,333	11
990,124					90,389,996		90,389,996	12
1,364,345					155,158,529		155,158,529	13
1					108		108	14
26,000,656	—	16,714,011	—	—	2,591,817,971	—	2,591,817,971	15

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also 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 projects load for this service in its system resource planning). In addition, the reliability 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 firm service which meets the definition of RQ service. For all transaction 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.

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 for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
14.01	COLLEGE OF NJ (TRENTON STATE)	OS	Orig Vol 1			
14.02	MONTCLAIR STATE UNIVERSITY	OS	Orig Vol 1			
14.03	NJR - 1250 SOUTH RIVER ROAD (SOLAR)	OS	Orig Vol 1			
14.04	NJR - 160 RARITAN CENTER - 95115	OS	Orig Vol 1			
14.05	NJR - 255 BLAIR ROAD	OS	Orig Vol 1			
14.06	NJR - 64 BRUNSWICK AVENUE - 95114	OS	Orig Vol 1			
14.07	PEERLESS BEVERAGE	OS	Orig Vol 1			
14.08	DCO- BURLINGTON	OS	Orig Vol 1			
14.09	STC WOODBRIDGE SOLAR	OS	Orig Vol 1			
14.10	PB NUTCLIF MASTER, LLC	OS	Orig Vol 1			
14.11	TRENTON BIOGASS, LLC	OS	Orig Vol 2			
14.12	WESTMONT (100 Johnson Avenue)	OS	Orig Vol 1			
14.13	HOME DEPOT-180 12th AVE, JERSEY CITY	OS	Orig Vol 1			
14.14	HOME DEPOT-1621 N. Olden Ave, Ewing	OS	Orig Vol 1			
15	Total			—	—	—

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC 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 provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (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 columns (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 (l) 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.

MegaWatt Hours Purchased	MegaWatt Hours Purchased for Energy Storage	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
		MegaWatt Hours Received	MegaWatt Hours Delivered	Demand Charges ($)	Energy Charges ($)	Other Charges ($)	Total (k+l+m) of Settlement ($)	
(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
1,545					66,130		66,130	14.01
1,221					67,070		67,070	14.02
601					24,332		24,332	14.03
411					16,387		16,387	14.04
1,054					42,751		42,751	14.05
788					30,517		30,517	14.06
68					2,681		2,681	14.07
97					2,870		2,870	14.08
286					11,622		11,622	14.09
106					2,644		2,644	14.10
11,435					723,312		723,312	14.11
117					4,429		4,429	14.12
43					1,165		1,165	14.13
318					11,527		11,527	14.14
26,000,656	—	16,714,011	—	—	2,591,817,971	—	2,591,817,971	15

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also 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 projects load for this service in its system resource planning). In addition, the reliability 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 firm service which meets the definition of RQ service. For all transaction 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.

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 for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
14.15	HOME DEPOT-7605 TONNELLE AVE STR, NORTH BERGEN TWP	OS	Orig Vol 1			
14.16	HOME DEPOT-4095 RTE 1 STR, SOUTH BRUNSWICK TW	OS	Orig Vol 2			
14.17	ZEC's Purchases	RQ	Orig Vol 1			
14.18	NITS BGS ADJUSTMENTS	RQ	Sch No 1			
14.19	BGS PJM Transmission Line Items	RQ	Sch No 1			
14.20	System Load Adjustment	RQ	Sch No 1			
14.21	Municipal	OS	Orig Vol 1			
14.22	Third Party Suppliers	RQ	Sch No 1			
14.23						
14.24						
14.25						
14.26						
14.27						
14.28						
15	Total			—	—	—

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC 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 provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (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 columns (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 (l) 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.

MegaWatt Hours Purchased	MegaWatt Hours Purchased for Energy Storage	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
		MegaWatt Hours Received	MegaWatt Hours Delivered	Demand Charges ($)	Energy Charges ($)	Other Charges ($)	Total (k+l+m) of Settlement ($)	
(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
174					6,216		6,216	14.15
370					14,441		14,441	14.16
—					64,250,212		64,250,212	14.17
—					(1,122,442,361)		(1,122,442,361)	14.18
—					1,177,918,242		1,177,918,242	14.19
334,325					—		—	14.20
—		171,962			—		—	14.21
—		16,542,049			—		—	14.22
—					—		—	14.23
—					—		—	14.24
—					—		—	14.25
—					—		—	14.26
—					—		—	14.27
—					—		—	14.28
26,000,656	—	16,714,011	—	—	2,591,817,971	—	2,591,817,971	15

FOOTNOTE DATA

Schedule Page: 326-327 Line No.: 15 Column: n

Total Purchase Power differs from FERC account 555 by $116,814,824 due to deferred NUG, ZEC and BGS Power Expense.

Pg. 327.4, Total (n)	$	2,591,817,971	
Pg. 321, line 76 (b)	$	2,700,046,465	
BGS, NUG, ZEC Def	$	(108,228,494)	
BGS Deferral	$	(1,206,327)	*(1)
NUG Deferral	$	60,141	*(2)
ZEC Deferral	$	1,156,447	*(3)
TREC program costs	$	(104,252,432)	*(4)
SuSI program costs	$	(3,986,323)	*(5)
Total	$	(108,228,494)	

*(1)-BGS deferral item relates primarily to collections from ratepayers for certain TEC charges not passed on to suppliers pending final resolution of appeals filed with FERC by the NJBPU

*(2) NUG deferral item (Non-Utility Generation) relates to collections from ratepayers for the difference between the contract-set prices for purchased generation from non-utility generators and the market price that the energy is sold for through the PJM Interconnection, LLC.

*(3)-ZEC deferral item relates to an overcollection of ZEC Energy charges from customers not paid to qualifying nuclear units under the terms of NJBPU's ZEC Order.

*(4) TREC Program Costs deferral item (Transition Renewable Energy Certificate) is a component of the GPRC program which represents costs of the over or under collected balances associated with “Transition Renewable Energy Certificates” awarded to qualifying solar projects, which replaces the Solar Renewable Energy Certificate (SREC) Program, as approved by the NJ BPU.

*(5) SuSI Program Costs deferral item (Successor Solar Incentive Program) is a component of the GPRC program which represents costs of the over or under collected balances associated with Solar Renewable Energy Certificate-IIs (SREC-IIs) awarded to qualifying solar projects. The SuSI Program replaces the Transition Renewable Energy Certificate (TREC) Program to serve as the permanent program for providing solar incentives to qualified solar electric generation facilities.

Schedule Page: 326-327 Line No.: 14.19 Column: n

The credit adjustment is to reduce Purchase Power by the Network Transmission Service BGS portion that is built into overall BGS rate; the offset is in FERC account 456.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
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: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	PJM Network Transmission Service			
2	PJM Firm PTP Transmission Service			
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
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16				
17				
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29				
30				
31				
32				
33				
34				
35	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

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.
8. Report in column (i) and (j) the total megawatthours received and delivered.

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.
				Hours Received (i)	Hours Delivered (j)	
		PJM Network				1
		Various				2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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						31
						32
						33
						34
			—	—	—	35

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

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 (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only 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.
689,824,719			689,824,719	1
		31,492,783	31,492,783	2
			—	3
			—	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
689,824,719	—	31,492,783	721,317,502	35

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

No.	Description	Amount
	(a)	(b)
1	Industry Association Dues	
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Miscellaneous Business Expenses	
7	Board of Directors Fees & Expenses	2,684,014
8	Standard & Poors/Moody's Rating Agency Fees	393,248
9	New York Stock Exchange (NYSE) - Listing Fees	226,285
10		
11		
12	Membership Fees	
13	Edison Electric Institute (EEI)	630,419
14	National Electric Energy Testing, Research & Applications Center (NEETRAC)	55,000
15	New Jersey Utilities Association (NJUA)	44,854
16	E Source Companies LLC.	5,179
17		
18	**Total Membership Fees**	735,452
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	Corporate Secretary	1,197,231
41	Investor Relations	671,717
42		
43		
44		
45		
46	TOTAL	5,907,947

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of acquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 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 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 sub-account used.
   In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing 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 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)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant	—	—	—	—	—
2	Steam Production Plant	—	—	—	—	—
3	Nuclear Production Plant	—	—	—	—	—
4	Hydraulic Production Plant-Conventional	—	—	—	—	—
5	Hydraulic Production Plant-Pumped Storage	—	—	—	—	—
5.1	Solar Production Plant	35,751,856	—	—	—	35,751,856
5.2	Wind Production Plant	—	—	—	—	—
5.3	Other Renewable Production Plant	—	—	—	—	—
6	Other Production Plant	—	—	—	—	—
7	Transmission Plant	377,723,407	—	76,656	—	377,800,063
8	Distribution Plant	351,713,080	—	—	—	351,713,080
9	Regional Transmission and Market Operation	—	—	—	—	—
9.1	Energy Storage Plant	—	—	—	—	—
10	General Plant	10,983,178	—	—	—	10,983,178
11	Common Plant - Electric	10,835,555	—	9,420,203	—	20,255,758
12	Total	787,007,076	—	9,496,859	—	796,503,935

B. Basis for Amortization Charges

13

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	**Electric Distribution Plant**						
13							
14	E360.3	1,218	103	— %	0.97 %	65-S2.5	50
15	E361	293,093	42	85 %	2.37 %	70-S1.5	29
16	E362	1,941,457	37	15 %	2.72 %	45-S0	31
17	E363.1	12,574	7	— %	14.29 %	—	4
18	E363.2	269,586	0	— %	— %	—	0
19	E363.3	116,935	10	— %	10.00 %	—	10
20	E364	1,373,317	28	110 %	3.59 %	65-R2.5	19
21	E365	3,815,388	62	8 %	1.62 %	60-R1	52
22	E366	557,640	96	13 %	1.04 %	75-R4	56
23	E367	1,644,678	57	18 %	1.74 %	58-R2	38
24	E368	1,952,374	33	41 %	3.02 %	55-R2	24
25	**E369**	**575,918**	57	—	1.76 %	65-R4	32
26	E370	478,461	10	66 %	9.89 %	20-L0.5	10
27	E373	534,545	31	22 %	3.26 %	38-R1	25
28	**Total Electric Distribution Plant**	13,567,184					
29							
30	Electric Transmission Plant						
31							
32	E350	574	89	— %	1.12 %	65-S2.5	52
33	E351.1	5,983	7	— %	14.29 %	—	0
34	E351.2	3,784	0	— %	— %	—	0
35	E351.3	92,214	10	— %	10.00 %	—	0
36	E352	616,060	69	5 %	1.44 %	75-S3	69
37	E353	9,074,640	45	10 %	2.24 %	52-R1.5	45
38	E354	1,531,664	79	5 %	1.27 %	70-R3	79
39	**E355**	**599,099**	68	—	1.47 %	65-R4	68
40	E356	3,227,984	47	15 %	2.11 %	55-R1.5	47
41	E357	598,852	93	— %	1.07 %	75-R4	93
42	E358	2,453,106	39	10 %	2.54 %	45-R2	39
43	E359	9,137	175	— %	0.57 %	60-R2.5	44
44	Total Electric Transmission Plant	18,213,097					
45							
46							
47							
48							
49							
50							

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)
49.01	**Electric Portion of General Plant**						
49.02							
49.03	303	—	0	— %	— %	—	0
49.04	390	44,478	0	— %	1.40 %	—	0
49.05	390.11	165	0	— %	— %	—	0
49.06	390.3	—	0	— %	— %	—	0
49.07	391.1	11,672	0	— %	5.00 %	—	0
49.08	391.2	1,082	0	— %	25.00 %	—	0
49.09	391.3	2	0	— %	14.29 %	—	0
49.10	391.33	—	0	— %	33.33 %	—	0
49.11	392.11	28,120	0	— %	— %	—	0
49.12	392.2	193,839	0	— %	— %	—	0
49.13	392.3	—	0	— %	— %	—	0
49.14	393	1,451	0	— %	14.29 %	—	0
49.15	394	19,910	0	— %	14.29 %	—	0
49.16	395	1,949	0	— %	20.00 %	—	0
49.17	396	40,266	0	— %	— %	—	0
49.18	397.1	—	0	— %	— %	—	0
49.19	397.2	—	0	— %	— %	—	0
49.20	**397.3**	854	0	— %	10.00 %	—	0
49.21	398	2,485	0	— %	14.29 %	—	0
49.22	Total Electric Portion of General Plant	**346,273**					
49.23							
49.24	Solar Plant						
49.25							
49.26	338.4	577,186,838	20	— %	5.00 %	—	7
49.27	338.4	27,217,304	15	— %	6.67 %	—	0
49.28	338.6	12,582,160	20	— %	5.00 %	—	10
49.29	338.6	607,890	15	— %	6.67 %	—	7
49.30	338.7	22,209,473	5	— %	20.00 %	—	2
49.31	338.8	2,504,248	20	— %	5.00 %	—	9
49.32	338.8	95,486	15	— %	6.67 %	—	0
49.33	338.1	4,441,216	9	—	11.11 %	—	7
49.34	338.11	1,369,920	5	— %	20.00 %	—	5
49.35	Total Solar Plant	648,214,535					
49.36							
49.37							
49.38							

FOOTNOTE DATA

Schedule Page: 336 Line No.: 12 Column: b

Page 219 Depreciation Expense	788,662,649
Less capitalized depreciation	(16,008,361)
Add common depreciation - electric	10,835,555
Less depreciation of regulatory accounts	3,517,233
Add Electric Distribution Deferred Depreciation	—
Total Adjustments	(1,655,573)
Page 336 Depreciation Expense	787,007,076

Schedule Page: 337.1 Line No.: 18 Column: e

Applied Depr. rates (percent) Various —%

Schedule Page: 337.1 Line No.: 34 Column: e

Applied Depr. rates (percent) Various —%

Schedule Page: 337.1 Line No.: 49.03 Column: e

Applied Depr. rates (percent) Various —%

Schedule Page: 337.1 Line No.: 49.04 Column: e

The Applied Depreciation Rate of 1.40%, is the applied rate for general plant structures and improvements as approved by FERC. In October 2024, the NJBPU approved a .99% applied rate for general plant structures and improvements specific to the support of electric distribution.

Schedule Page: 337.1 Line No.: 49.05 Column: e

Applied Depr. rates (percent) Various —%

Schedule Page: 337.1 Line No.: 49.06 Column: e

Applied Depr. rates (percent) Various —%

Schedule Page: 337.1 Line No.: 49.11 Column: e

Applied Depr. rates (percent) Various —%

Schedule Page: 337.1 Line No.: 49.12 Column: e

Applied Depr. rates (percent) Various —%

Schedule Page: 337.1 Line No.: 49.17 Column: e

Applied Depr. rates (percent) Various —%

Schedule Page: 337 Line No.: 15-28 Column: b

Data field was updated to correctly state previously reported amounts.

Schedule Page: 337.1 Line No.: 49.18-49.22 Column: a-g

Data field was updated to correctly state previously reported amounts.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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 format 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 Expense for Current Year (b) +(c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	NJ Board of Public Utilities	12,701,454		12,701,454	
2	NJ Division of Rate Counsel	3,077,201		3,077,201	
3	Other Misc Regulatory Studies		13,305	13,305	
4				—	
5				—	
6	FERC			—	
7	Various FERC Transmission Matters		384,042	384,042	
8				—	
9				—	
10				—	
11				—	
12				—	
13				—	
14				—	
15				—	
16				—	
17				—	
18				—	
19				—	
20				—	
21				—	
22				—	
23				—	
24				—	
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27				—	
28				—	
29				—	
30				—	
31				—	
32				—	
33				—	
34				—	
35				—	
36				—	
37				—	
38				—	
39				—	
40				—	
41				—	
42				—	
43				—	
44				—	
45				—	
46	TOTAL	15,778,655	397,347	16,176,002	—

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department	Account	Amount					
(f)	(g)	(h)	(i)	(j)	(k)	(l)	
Electric	928	12,701,454					1
Electric	928	3,077,201					2
Electric	928	13,305					3
							4
							5
							6
Electric	928	384,042					7
							8
							9
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		16,176,002	—		—	—	46

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (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	None.
4	i. Recreation fish and wildlife	None.
5	ii. Other hydroelectric	None.
6	b. Fossil-fuel steam	None.
7	c. Internal combustion or gas turbi	None.
8	d. Nuclear	None.
9	e. Unconventional generation	None.
10	f. Siting and heat rejection	None.
11	(2) Transmission	0
12	a. Overhead	EPRI - Electric Transmission OH
13		CEATI - Electric Transmission OH
14		Neetrac - Electric Transmission OH
15	b. Underground	EPRI - Electric Transmission UG
16		CEATI - Electric Transmission UG
17		Neetrac - Electric Transmission UG
18	c. Station Analytics	EPRI - Electric Transmission ST
19		Neetrac - Electric Transmission ST
20	d. Other	CEATI - Electric Transmission Asset Management Program
21		Total Transmission
22	(3) Distribution	0
23	a. Overhead	Neetrac - Electric Distribution OH
24	b. Underground	Neetrac - Electric Distribution UG
25	c. Station Analytics	Neetrac - Electric Distribution ST
26	d. Other	CEATI - Electric Distribution
27		Total Distribution
28		Grand Total Transmission & Distribution
29	(4) Regional Transmiss and Market Operation	None.
30	(5) Environment (other than equipement)	None.
31	(6) Other (Classify & Incl item < $50,000)	None.
32	(7) Total Cost Incurred	0
33		0
34	B. Electric, R, D & D Performed Externally	0
35	(1) Research Support to the electrical	0
36	Research Council or the EPRI	None.
37	(2) Research Support to EEI	None.
38	(3) Research Support to Nuclear Power Group	None.
39	(4) Research Support to Other (Classify)	None.
40	(5) Total Cost Incurred	

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 $50,000 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 $50,000 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 accumulating 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.

Cost Incurred Internally Current Year	Costs Incurred Externally Current Year	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation	Line No.
		Account	Amount		
(c)	(d)	(e)	(f)	(g)	
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
3,668	506,682	563	510,350		12
2,322	74,769	563	77,091		13
—	22,000	563	22,000		14
8,296	424,287	564	432,583		15
3,451	26,831	564	30,282		16
—	23,100	564	23,100		17
111	611,458	562	611,569		18
—	9,900	562	9,900		19
4,602	20,000	566	24,602		20
22,451	**1,719,027**	0.00	**1,741,477**		21
0	—	0.00			22
—	36,400	583	36,400		23
—	38,220	584	38,220		24
—	16,380	582	16,380		25
—	41,676	582, 583, 584	41,676		26
—	**132,676**	0.00	**132,676**		27
22,451	**1,851,703**		**1,874,153**		28
					29
					30
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					40

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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			
4	Transmission	27,135,908		
5	Regional Market	—		
6	Distribution	55,493,010		
7	Customer Accounts	60,624,834		
8	Customer Service and Informational	6,196,507		
9	Sales	74,499		
10	Administrative and General	12,602,070		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	162,126,828		
12	Maintenance			
13	Production			
14	Transmission	25,057,457		
15	Regional Market	—		
16	Distribution	44,318,498		
17	Administrative and General	—		
18	TOTAL Maintenance (Total of lines 13 thru 17)	69,375,955		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	—		
21	Transmission (Enter Total of lines 4 and 14)	52,193,365		
22	Regional Market (Enter Total of Lines 5 and 15)	—		
23	Distribution (Enter Total of lines 6 and 16)	99,811,508		
24	Customer Accounts (Transcribe from line 7)	60,624,834		
25	Customer Service and Informational (Transcribe from line 8)	6,196,507		
26	Sales (Transcribe from line 9)	74,499		
27	Administrative and General (Enter Total of lines 10 and 17)	12,602,070		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	231,502,783		231,502,783
29	Gas			
30	Operation			
31	Production-Manufactured Gas	1,011,355		
32	Production-Nat. Gas (Including Expl. and Dev.)	—		
33	Other Gas Supply	1,198		
34	Storage, LNG Terminaling and Processing	229,342		
35	Transmission	430,836		
36	Distribution	112,913,060		
37	Customer Accounts	50,432,550		
38	Customer Service and Informational	3,700,998		
39	Sales	137,536		
40	Administrative and General	9,978,306		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	178,835,181		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	206,684		
47	Transmission	120,544		

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	18,234,684		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	18,561,912		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	1,011,355		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,	—		
54	Other Gas Supply (Enter Total of lines 33 and 45)	1,198		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	436,026		
56	Transmission (Lines 35 and 47)	551,380		
57	Distribution (Lines 36 and 48)	131,147,744		
58	Customer Accounts (Line 37)	50,432,550		
59	Customer Service and Informational (Line 38)	3,700,998		
60	Sales (Line 39)	137,536		
61	Administrative and General (Lines 40 and 49)	9,978,306		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	197,397,093		197,397,093
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	428,899,876	—	428,899,876
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	372,162,985		372,162,985
69	Gas Plant	233,555,950		233,555,950
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	605,718,935	—	605,718,935
72	Plant Removal (By Utility Departments)			
73	Electric Plant	36,435,896		36,435,896
74	Gas Plant	21,184,666		21,184,666
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	57,620,562	—	57,620,562
77	Other Accounts (Specify, provide details in footnote):			
78	Electric Expenses for civic, political and related activities	1,121,417		1,121,417
79	Electric work done at the expense of others	7,566,557		7,566,557
80	Gas work done at the expense of others	1,742,276		1,742,276
81	DSM/other deferred	42,047,875		42,047,875
82	CoOwner	481,384		481,384
83	Gas Expenses for Civic, political and related activities	133,861		133,861
84	Work For Affiliates	3,279,410		3,279,410
85	Non-Utility Operations	15,604,106		15,604,106
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	71,976,886	—	71,976,886
96	TOTAL SALARIES AND WAGES	1,164,216,259	—	1,164,216,259

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.

COMMON UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION
ALLOCATED TO UTILITY OPERATIONS

COMMON UTILITY PLANT
PLANT IN SERVICE (ACCT.101)

		ELECTRIC	GAS	TOTAL
C303	INTANGIBLE PLANT	61,672,122	50,459,010	112,131,132
C389	LAND & LAND RIGHTS	57,842	47,325	105,167
C390	STRUCTURE & IMPROVEMENTS	47,120,918	38,546,834	85,667,752
C391	OFFICE FURNITURE & EQUIPMENT	23,388,882 [1]	19,136,357 [2]	42,525,239 [3]
C392	TRANSPORT EQUIPMENT	11,920,056	9,518,922	21,438,978
C393	STORES EQUIPMENT	24,845	20,327	45,172
C394	TOOLS, SHOP AND GARAGE EQUIPT	1,327,227	1,085,913	2,413,140
C395	LABORATORY EQUIPMENT	—	—	—
C396	POWER OPERATED EQUIPMENT	3,388,142	2,772,116	6,160,258
C397	COMMUNICATION EQUIPMENT	36,011,798 [4]	29,464,198 [5]	65,475,996 [6]
C398	MISCELLANEOUS EQUIPMENT	9,519,148	7,788,394	17,307,542
	TOTAL PLANT IN SERVICE (ACCT.101)	194,430,980	158,839,396	353,270,376
	CONSTRUCTION WORK IN PROGRESS (ACCT.107)	41,476,953	33,930,586	75,407,539
	GRAND TOTAL (ACCT. 101 & 107)	235,907,933	192,769,982	428,677,915

ACCUMULATED PROVISIONS OF COMMON	ELECTRIC	GAS	TOTAL
UTILITY PLANT (ACCT. 108)	65,665,379	53,565,230	119,230,609
UTILITY PLANT (ACCT. 111)	43,966,082	35,972,249	79,938,331

Footnote 1-6:
Data field was updated to correctly state previously reported amounts.

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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Quarter 4 (e)
1	Energy				
2	Net Purchases (Account 555)	—	—	—	—
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	1,940,236	3,579,409	5,472,507	3,617,619
4	Transmission Rights				
5	Ancillary Services	(84,979)	146,458	(14,034)	(245,955)
6	Other Items (list separately)	—	—		
7	Transmission Congestion	24,765	(369,571)	(312,038)	(431,618)
8	Transmission Losses	33,785	5,417	25,301	(5,451)
9	Ramapo PAR Facilities	—	—		
10	Network Integration Transmission	151,491,142	153,191,975	156,601,739	157,615,460
11	Firm Point to Point Transmission	7,999,362	7,376,346	8,724,676	7,392,399
12	Other Supporting Facilities Credit	20,567	18,696	38,363	24,428
13	Service	775,366	560,973	443,886	479,971
14	PJM Customer Payment Defaults	—	—	—	—
15					
16					
17					
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40					
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45					
46	Total	162,200,244	164,509,703	170,980,400	168,446,853

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage-Related Billing Determinant			Usage-Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	18,634			42,695,815		4,717,395
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)	18,634		—	42,695,815		4,717,395

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☐ An Original (2) ☒ Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. 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 on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported in Column (b).
(4) Report on Columns (e) through (j) by month the system's monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month	Monthly Peak MW - Total	Day of Monthly Peak	Hour of Monthly Peak	Firm Network Service for Self	Firm Network Service for Others	Long-Term Firm Point-to-point Reservations	Other Long-Term Firm Service	Short-Term Firm Point-to-point Reservation	Other Service
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	January	6,761	21	18						
2	February	6,344	20	19						
3	March	5,581	3	20						
4	Total for Quarter 1				—	—	—	—	—	—
5	April	5,258	29	21						
6	May	5,818	3	19						
7	June	10,229	24	19						
8	Total for Quarter 2				—	—	—	—	—	—
9	July	10,019	29	19						
10	August	8,912	13	17						
11	September	7,026	5	18						
12	Total for Quarter 3				—	—	—	—	—	—
13	October	6,109	6	18						
14	November	5,521	11	18						
15	December	6,558	15	18						
16	Total for Quarter 4				—	—	—	—	—	—
17	Total Year to Date/Year				—	—	—	—	—	—

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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)	40,568,320
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	140,476
5	Hydro-Conventional		25	Energy Furnished Without Charge	168,419
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	23,645
6.1	Solar		27	Total Energy Losses	**1,954,283**
6.2	Wind		27.1	Total Energy Stored	
6.3	Other Renewable		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	**42,855,143**
7	Other	140,476			
8	Less Energy for Pumping				
9	Net Generation (Enter Total of lines 3 through 8)	140,476			
10	Purchases	26,000,656			
10.1	Purchases for Energy Storage				
11	Power Exchanges:				
12	Received	16,714,011			
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)	16,714,011			
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)	—			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	**42,855,143**			

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy (MWH)	Monthly Non-Requirements Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	3,675,647	7,853	6,761	21	18
30	February	3,209,882	8,992	6,344	20	19
31	March	3,083,752	13,666	5,581	3	20
32	April	2,780,148	13,349	5,258	29	21
33	May	2,959,841	13,601	5,818	3	19
34	June	3,714,944	13,508	10,229	24	19
35	July	4,632,099	16,761	10,019	29	19
36	August	3,887,571	15,731	8,912	13	17
37	September	3,283,574	12,837	7,026	5	18
38	October	2,940,988	12,425	6,109	6	18
39	November	2,814,374	6,407	5,521	11	18
40	December	3,585,500	5,346	6,558	15	18
41	Total	40,568,320	140,476			

FOOTNOTE DATA

Schedule Page: 401a Line No.: 10 Column: b

Purchases are based on derated volumes per supplier purchased power on pages 326-327.

Schedule Page: 401a Line No.: 22 Column: b

Sales to Ultimate Customers is compose of Basic Generation Service (BGS), Third Party Suppliers (TPS) sales, and Non-Utility Generator (NUGs)-Load Reducers

BGS MWHs	24,723,900
TPS MWHs	15,825,785
NUGs - Load Reducers MWHs	18,635
Sale, Pg. 401, line 22 (b)	40,568,320

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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	OTHER PRODUCTION - SOLAR					
2	Segement 1a - PSE&G Owned Sites	2010	16.00		19,029,668	95,265,909
3	Segement 1b - 3rd Party Owned Sites	2010	18.51		20,682,007	76,576,346
4	Segment 1c - Urban Enterprise Zone	2010	5.43		2,918,309	27,967,268
5	Segment 2 - Pole Tops	2009	40.00		32,120,173	267,033,560
6	Extension - Landfills and Pilot Projects	2014	41.99		46,607,611	102,824,095
7	Extension - Pilot Projects	2017	3.00		3,171,799	20,945,587
8	Extension 2 - Landfills and Pilots	2019	32.96		37,998,444	56,507,621
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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 the 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 (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)	Line No.
							1
5,954,119			680,597	Solar		Solar	2
4,137,026			409,201	Solar		Solar	3
5,150,510			107,170	Solar		Solar	4
6,675,839			4,574,510	Solar		Solar	5
2,453,154			657,180	Solar		Solar	6
6,981,862			219,362	Solar		Solar	7
1,806,597			376,221	Solar		Solar	8
							9
							10
							11
							12
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines) On Structure of Line Designated (f)	LENGTH (Pole miles) (In the case of underground lines) On Structures of Another (g)	Number Of Circuits (h)
1	Summary					
2	Joint Owned	Joint Owned				
3	500 kV	500 kV	SP/T	186.30	—	
4	345 kV	345 kV	SP/T	1.49	0.39	
5						
6	Wholly Owned	Wholly Owned				
7	500 kV	500 kV	SP/T	299.00	—	
8	345 kV	345 kV	SP/T	11.97	10.61	
9	345 kV	345 kV	UG	37.86	14.51	
10						
11	230 kV	230 kV	SP/T	395.39	326.40	
12	230 kV	230 kV	UG	172.43	0.40	
13						
14	138 kV	138 kV	SP/T	7.17	2.14	
15	138 kV	138 kV	UG	67.67	—	
16						
17	69 kV	69 kV	WP	597.98	2.96	1
18	69 kV	69 kV	UCB	90.67	—	1
19						
20						
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24						
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26						
27						
28						
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36			TOTAL	1,867.93	357.42	250

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 (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
			—				—	1
			—				—	2
	21,963,723	58,469,223	80,432,946	1,139,158	3,360,774	—	4,499,932	3
	262,779	2,615,068	2,877,847	11,496	33,914	—	45,410	4
							—	5
			—				—	6
	19,770,827	682,718,512	702,489,339	1,828,278	5,393,836	—	7,222,114	7
	—	439,424,566	439,424,566	138,069	407,334	—	545,403	8
	352,349	446,662,825	447,015,174	1,303,775	665,547	—	1,969,322	9
			—				—	10
	35,868,754	2,036,977,155	2,072,845,909	4,413,473	13,020,746	6,567,139	24,001,358	11
	10,171,502	1,368,774,194	1,378,945,696	4,302,682	2,196,418	—	6,499,100	12
			—				—	13
	3,082,835	79,437,277	82,520,112	56,927	167,949	—	224,876	14
	125,189	294,452,119	294,577,308	1,684,676	859,987	—	2,544,663	15
			—				—	16
800KCMIL	12,839,129	1,090,637,385	1,103,476,514	3,674,534	10,840,707	—	14,515,241	17
1500CU EPR	11,334,401	484,776,942	496,111,343	2,257,271	1,152,284	—	3,409,555	18
			—				—	19
			—				—	20
			—				—	21
			—				—	22
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			—				—	31
			—				—	32
			—				—	33
			—				—	34
			—				—	35
	115,771,488	6,984,945,266	7,100,716,754	20,810,339	38,099,496	6,567,139	65,476,974	36

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From	To	Operating	Designed		On Structure of Line Designated	On Structures of Another Line	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
35.001	**JOINTLY OWNED**							
35.002	CONEMAUGH-	MARYLAND BORDER {1}	500	500	SP/T	29.21		2
35.003	HOPE CREEK-	RED LION (River Crossing)	500	500	SP/T	19.41		2
35.004	DEANS-	BRANCHBURG {2}	500	500	SP/T	19.53		2
35.005	EAST WINDSOR	DEANS (3)	500	500	SP/T	15.37		2
35.006	SALEM-	NEW FREEDOM {2}	500	500	SP/T	50.28		2
35.007	NEW FREEDOM	EAST WINDSOR	500	500	SP/T	52.50		2
35.008	SO. MAHWAH-	RAMAPO {4}	345	345	SP/T	1.49	0.39	2
35.009								
35.010	**500 KV WHOLLY OWNED (BY PSE&G OR OTHERS)**							
35.011	BRANCHBURG-	ALBURTIS	500	500	SP/T	49.07	—	2
35.012	BRANCHBURG-	ELROY	500	500	SP/T	42.00		2
35.013	HOPATCONG-	RAMAPO	500	500	SP/T	34.21	—	2
35.014	SALEM-	ORCHARD	500	500	SP/T	19.00	—	2
35.015	HOPE CREEK-	NEW FREEDOM	500	500	SP/T	42.87	—	2
35.016	SALEM-	HOPE CREEK	500	500	SP/T	0.43	—	2
35.017	ORCHARD-	NEW FREEDOM	500	500	SP/T	24.02		2
35.018	HOPATCONG-	BRANCHBURG	500	500	SP/T	40.03	—	2
35.019	ROSELAND-	HOPATCONG	500	500	SP/T	25.19		3
35.020	HOPATCONG-	BUSHKILL	500	500	SP/T	22.18	—	3
35.021								
35.022	**345KV WHOLLY OWNED (BY PSE&G OR OTHERS)**							
35.023	HUDSON-	FARRAGUT	345	345	UG	3.68	—	1
35.024	HUDSON-	FARRAGUT	345	345	UG	3.55	—	1
35.025	MARION-	BAYONNE	345	345	UG	5.61	—	1
35.026	MARION-	BERGEN	345	345	SP/T	7.01	—	2
35.027	MARION-	BERGEN	345	345	SP/T	—	7.01	2
35.028	BAYWAY-	BAYONNE	345	345	UG	2.47	6.20	1
35.029	—	—	345	345	SP/T	0.26	—	2
35.030	BAYWAY-	NORTH AVE	345	345	UG	0.34	6.07	1
35.031	WALDWICK-	SO. MAHWAH-	345	345	UG	5.46	—	1
35.032	WALDWICK-	SO. MAHWAH--	345	345	UG	5.51	—	1
35.033	BAYONNE-	MARION	345	345	UG	4.58	—	1
35.034	LINDEN-	BAYWAY	345	345	SP/T	1.57	—	2
35.035	BAYWAY-	NEWARK AIRPORT	345	345	UG	3.23		1
36					TOTAL	1,867.93	357.42	250

TRANSMISSION LINE STATISTICS (Continued)

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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)	
			—				—	35.001
2493ACAR			—				—	35.002
2493ACAR			—				—	35.003
2493ACAR			—				—	35.004
2493ACAR							—	35.005
2493ACAR			—				—	35.006
2493ACAR			—				—	35.007
1590ACSR			—				—	35.008
			—				—	35.009
			—				—	35.010
2493ACAR			—				—	35.011
2493ACAR			—				—	35.012
2493ACAR			—				—	35.013
2493ACAR			—				—	35.014
2493ACAR			—				—	35.015
2493ACAR			—				—	35.016
2493/1590 ACAR			—				—	35.017
2493ACAR			—				—	35.018
1590ACSR			—				—	35.019
1590ACSR			—				—	35.020
			—				—	35.021
			—				—	35.022
2000KCM CU.			—				—	35.023
2000KCM CU.			—				—	35.024
3500KCM CU.			—				—	35.025
1590ACSR			—				—	35.026
1590ACSR			—				—	35.027
5000/3500KCM			—				—	35.028
1590ACSR			—				—	35.029
5000KCM CU.			—				—	35.030
3500KCM CU.			—				—	35.031
3500KCM CU.			—				—	35.032
3000KCM CU.			—				—	35.033
1590ACSR			—				—	35.034
3500KCM CU.			—	—	—	—	—	35.035
	115,771,488	6,984,945,266	7,100,716,754	20,810,339	38,099,496	6,567,139	65,476,974	36

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) 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)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structures of Another Line (g)	Number Of Circuits (h)
35.036	**345KV WHOLLY OWNED (BY PSE&G OR OTHERS)**							
35.037	NORTH AVE-	NEWARK AIRPORT	345	345	UG	0.47	1.14	1
35.038	NORTH AVE-	NEWARK AIRPORT	345	345	UG	0.32	1.10	1
35.039	LINDEN-	BAYWAY	345	345	SP/T	1.64	—	2
35.040	BAYWAY-	NORTH AVE	345	345	UG	2.64	—	1
35.041	LINDEN-	BAYWAY-	345	345	SP/T	—	1.57	2
35.042	LINDEN--	BAYWAY	345	345	SP/T	—	1.64	2
35.043	SO. MAHWAH--	RAMAPO {4}-	345	345	SP/T	1.49	0.39	1
35.044								
35.045	**230KV WHOLLY OWNED (BY PSE&G OR OTHERS)**							
35.046	MERCER-	KUSER RD.	230	230	SP/T	10.38	—	1
35.047	ESSEX-	HUDSON	230	230	SP/T	6.19	—	1
35.048	LINDEN	GULF OIL (Customer)	230	230	SP/T	3.00		2
35.049	BURLINGTON-	CINNAMINSON	230	230	SP/T	13.71	—	1
35.050	McCARTER	ORANGE HEIGHT	230	230	UG	4.41	—	1
35.051	BERGEN-	ATHENIA	230	345	UG	10.94	—	1
35.052	MERCER-	TRENTON	230	230	SP/T	3.97		1
35.053	CEDAR GROVE	CLIFTON	230	230	SP/T	3.72		1
35.054	LINDEN#2	TOSCO (Customer)	230	230	SP/T	0.86	—	1
35.055	BURLINGTON	—	230	230	SP/T	6.84	—	1
35.056	Kearny-	Kingsland	230	230	SP/T	1.89	2.67	1
35.057	ROSELAND-	LIVINGSTON	230	230	SP/T	1.00	—	1
35.058	BRANCHBURG-	SOMERVILLE	230	230	SP/T	9.23	—	1
35.059	CAMDEN-	RICHMOND	230	230	SP/T	2.16	—	2
35.060	NEW FREEDOM-	—	230	230	SP/T	5.68	—	1
35.061	MEADOWS	NEW WASHINGTON	230	230	SP/T	—	6.17	1
35.062	CUTHBERT-	GLOUCESTER	230	230	UG	5.71		1
35.063	ATHENIA-	BERGEN	230	345	UG	9.57	—	1
35.064	DEANS-	BRUNSWICK	230	230	SP/T	3.55	—	1
35.065	CROYDEN-	BURLINGTON	230	230	SP/T	1.71	—	1
35.066	GLOUCESTER-	CUTHBERT BLVD.	230	230	UG	4.44	—	1
35.067	MERCER	WHITE HORSE	230	230	SP/T	1.69	—	1
35.068	DEVILS BROOK	TRENTON	230	230	SP/T	13.20		1
35.069	ROSELAND-	MONTVILLE	230	500	SP/T	0.09	7.21	1
35.070	LEVITTOWN-	COX'S CORNER	230	230	SP/T	10.30	0.55	1
36					TOTAL	1,867.93	357.42	250

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)	
								35.036
5000KCM CU.								35.037
5000KCM CU.								35.038
1590ACSR								35.039
3000KCM CU.								35.040
1590ACSR								35.041
1590ACSR								35.042
1590ACSR								35.043
								35.044
								35.045
1590ACSR								35.046
1590ACSR								35.047
804.5/1590ACSR								35.048
1033.5/1590ACSR/ACSS								35.049
3500KCM CU.								35.050
3500KCM CU.								35.051
1590ACSR								35.052
1590ACSR								35.053
1590ACSS/ACSS/AW								35.054
1590/1033.5 ACSR/ACSS								35.055
1590ACSS/ACSR/AW								35.056
1590ACSR								35.057
1033/1590ACSS/AW/ACSR								35.058
1590ACSR								35.059
1590ACSR								35.060
1590ACSR								35.061
3500KCM CU.								35.062
3500KCM CU.								35.063
1590ACSR								35.064
1590/1192.5ACSR/ACSS								35.065
3000KCM CU.								35.066
1590ACSR								35.067
1590ACSR								35.068
1590ACSR								35.069
1590ACSR								35.070
	115,771,488	6,984,945,266	7,100,716,754	20,810,339	38,099,496	6,567,139	65,476,974	36

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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)
35.071	**230KV WHOLLY OWNED (BY PSE&G OR OTHERS)**							
35.072	WALDWICK-	HAWTHORNE	230	230	UG	4.19	—	1
35.073	NEW FREEDOM	ECHELON	230	230	SP/T	—	12.04	1
35.074	TRANSCO WILLIAMS-	CEDAR GROVE	230	230	SP/T	7.60		1
35.075	BRUNSWICK-	SUNNYMEADE	230	230	SP/T	10.06	—	1
35.076	HILLSDALE-	WALDWICK	230	230	UG	5.44	—	1
35.077	BURLINGTON-	COX'S CORNER	230	230	SP/T	3.21	9.95	1
35.078	KEARNY-	HUDSON	230	230	SP/T	1.78		1
35.079	SADDLE BROOK-	ATHENIA	230	345	UG	4.41	—	1
35.080	DEANS-	SEWAREN	230	230	SP/T	5.66	16.93	1
35.081	LAWRENCE SW	LAWRENCE SUB	230	230	SP/T	0.07	—	1
35.082	SADDLE BROOK-	MAYWOOD	230	230	UG	2.71	—	1
35.083	SPRINGFIELD RD.-	ALDENE	230	230	UG	3.46	—	1
35.084	KEARNY-	HUDSON	230	230	SP/T	—	1.72	1
35.085	BEAVER BROOK	HILLTOP	230	230	SP/T	2.39	—	1
35.086	BERGEN II-	RIDGEFIELD	230	230	SP/T	1.01	—	1
35.087	CLIFTON AVE	TRENTON	230	230	SP/T	0.13	2.32	1
35.088	LINDEN#2-	LINDEN	230	230	SP/T	0.30		1
35.089	FANWOOD-	METUCHEN	230	230	SP/T	3.25	5.04	1
35.090	HUDSON-	SOUTH WATERFRONT	230	345	UG	3.42	—	1
35.091	MAINSFIELD	WARD AVE	230	230	SP/T	—	6.10	1
35.092	BRIDGEWATER-	MIDDLESEX	230	230	SP/T	6.23	—	1
35.093	BRANCHBURG-	EAST FLEMINGTON	230	230	SP/T	7.09	—	1
35.094	GLOUCESTER-	BEAVER BROOK	230	230	SP/T	3.43	—	1
35.095	MERCER	WF - COGEN	230	230	SP/T	1.59	1.96	1
35.096	ROSELAND-	FRONT STREET	230	230	SP/T	14.91	—	2
35.097	BELLEVILLE-	HUDSON	230	230	SP/T	4.63	1.20	1
35.098	NEWPORT	HOBOKEN	230	230	UG	2.21	—	1
35.099	ESSEX -	NEWARK BAY COGEN.	230	230	UG	—	—	1
35.100	MAYWOOD-	NEW MILFORD	230	230	UG	4.47	—	1
35.101	—	—	230	230	SP/T	0.05	—	1
35.102	GLOUCESTER-	CAMDEN COGEN.	230	230	UG	3.64	—	1
35.103	ROSELAND-	WEST ORANGE	230	230	SP/T	4.40		1
35.104	McCARTER	STANLEY TERRACE	230	230	UG	6.82	—	1
35.105	HUDSON	PENHORN	230	230	SP/T	1.66	—	1
36					TOTAL	1,867.93	357.42	250

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)	
								35.071
2000/2500KCM CU.								35.072
1590ACSR								35.073
1590ACSR								35.074
1590ACSR								35.075
3500KCM CU.								35.076
1590ACSR								35.077
1590ACSS								35.078
3500KCM CU.								35.079
1590ACSR								35.080
1590ACSR								35.081
2000/2500KCM CU.								35.082
3000KCM CU.								35.083
1590ACSS								35.084
1590ACSR								35.085
1590ACSS/AW								35.086
1590ACSR								35.087
1590ACSR								35.088
1590ACSR								35.089
3500KCM CU.								35.090
1590ACSS/AW								35.091
1590ACSR								35.092
1590ACSR/ACSS/AW								35.093
1590ACSR								35.094
1590/795ACSR								35.095
1590ACSR								35.096
1590ACSR								35.097
1033.5/1590ACSS/ACSR								35.098
2000KCM CU.								35.099
3500KCM CU.								35.100
1590ACSS								35.101
2000KCM CU.								35.102
1590ACSR								35.103
2500/3500/3000KCMIL CU/AL								35.104
1590ACSR								35.105
	115,771,488	6,984,945,266	7,100,716,754	20,810,339	38,099,496	6,567,139	65,476,974	36

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
35.106	**230KV WHOLLY OWNED (BY PSE&G OR OTHERS)**							
35.107	KITTATINNY-	BUSHKILL	230	230	SP/T	10.89	—	1
35.108	ESSEX-	McCARTER	230	230	UG	6.44	—	1
35.109	NEW FREEDOM-	HILLTOP	230	230	SP/T	10.09		1
35.110	ATHENIA-	CEDAR GROVE	230	230	SP/T	0.19	3.52	1
35.111	RIDGEFIELD-	LEONIA	230	230	UG	2.99	—	1
35.112	ROSELAND	KINGSLAND	230	230	SP/T	—	17.28	1
35.113	RANCOCAS	CINNAMINSON	230	230	SP/T	2.11	—	1
35.114	SOUTH WATERFRONT-	NEWPORT	230	230	UG	1.46	—	1
35.115	ROCKTOWN-	BUCKINGHAM	230	230	SP/T	3.32	—	1
35.116	LIVINGSTON	WEST ORANGE	230	230	SP/T	3.42	—	1
35.117	KEARNY	ESSEX	230	230	SP/T	1.22		1
35.118	TRENTON	WARD AVE	230	230	SP/T	—	5.86	1
35.119	JACKSON RD-	HINCHMANS	230	230	UG	4.01	—	1
35.120	READINGTON-	BRANCHBURG	230	230	SP/T	4.82	—	1
35.121	LEVITTOWN-	CAMDEN	230	230	SP/T	0.33	9.54	1
35.122	KEARNY	ROSELAND	230	230	SP/T	21.88		1
35.123	RIDGEFIELD-	NORTH BERGEN	230	230	SP/T	—	2.14	0
35.124	MONTVILLE-	NEWTON	230	500	SP/T	—	24.78	1
35.125	WARINANCO-	ALDENE	230	230	SP/T	3.08		1
35.126	HINCHMANS-	HAWTHORNE	230	230	UG	5.57		1
35.127	WEST ORANGE-	SPRINGFIELD RD	230	230	UG	8.87	—	1
35.128	BRANCHBURG-	BRIDGEWATER	230	230	SP/T	3.21	9.06	1
35.129	BRUNSWICK	NEW DEY	230	230	SP/T	10.30		2
35.130	SOMERVILLE-	BRIDGEWATER	230	230	SP/T	0.16	2.86	1
35.131	EAGLE POINT-	MICKLETON	230	230	SP/T	6.61	0.58	2
35.132	FAIRLAWN-	WALDWICK	230	230	UG	5.46	—	1
35.133	BERGENFIELD-	NEW MILFORD	230	230	UG	2.70	—	1
35.134	—	—	230	230	SP/T	0.06	—	2
35.135	ALDENE-	STANLEY TERRACE	230	230	UG	6.31	—	1
35.136	HARVEY	NEW WASHINGTON	230	230	SP/T	—	5.19	1
35.137	KEARNY-	MEADOWS	230	230	SP/T	0.34	0.51	1
35.138	GLOUCESTER-	EAGLE POINT	230	230	SP/T	2.89		2
35.139	HUDSON-	SOUTH WATERFRONT	230	230	UG	3.08	—	1
35.140	BERGENFIELD-	LEONIA	230	230	UG	4.24		1
36					TOTAL	1,867.93	357.42	250

TRANSMISSION LINE STATISTICS (Continued)

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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.
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	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
								35.106
1590ACSR								35.107
2000/2500/3000KCM CU.								35.108
1590ACSR								35.109
1590ACSR								35.110
2000/2500KCM CU.								35.111
1590ACSR/ACSS/AW								35.112
1033.5/1590ACSS/ACSR								35.113
2000KCM CU.								35.114
1590ACSS/AW								35.115
1590ACSR								35.116
1590ACSR								35.117
1590ACSS								35.118
2000/2500KCM CU.								35.119
1590ACSS/AW								35.120
1590ACSR								35.121
1590ACSS/AW/ACSR								35.122
1590ACSR								35.123
1590/2493ACSR/ACAR								35.124
1033.5ACSS/AW Curlew								35.125
2000/2500KCM CU.								35.126
3000KCM CU.								35.127
1590ACSS/AW/ACSR								35.128
1590 ACSR								35.129
1590ACSS/AW/ACSR								35.130
1033.5ACSS/ACSR								35.131
3500KCM CU.								35.132
2500/2000KCM CU.								35.133
1590ACSS/AW								35.134
2500/2000KCM CU.								35.135
1590ACSR								35.136
1590ACSR								35.137
1033.5ACSS								35.138
3000KCMIL								35.139
2500/2000KCM CU.								35.140
	115,771,488	6,984,945,266	7,100,716,754	20,810,339	38,099,496	6,567,139	65,476,974	36

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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.
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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) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
35.141	**230KV WHOLLY OWNED (BY PSE&G OR OTHERS)**							
35.142	COX'S CORNER-	LUMBERTON	230	230	SP/T	—	4.31	1
35.143	TRENTON	BURLINGTON	230	230	SP/T	—	5.86	2
35.144	ATHENIA-	SADDLE BROOK	230	230	UG	4.75	—	1
35.145	EAST FLEMINGTON-	PLEASANT VALLEY	230	230	SP/T	7.55	4.24	1
35.146	SOUTH WATERFRONT-	NEWPORT	230	230	UG	1.28	—	1
35.147	CAMDEN-	CINNAMINSON	230	230	SP/T	4.84	—	1
35.148	SEWAREN-	LINDEN#2-	230	230	SP/T	—	5.88	1
35.149	SEWAREN--	LINDEN#2	230	230	SP/T	—	5.98	1
35.150	HOBOKEN	49TH STREET SUB	230	230	UG	3.43	—	1
35.151	49TH STREET SUB-	NORTH BERGEN	230	230	SP/T	0.34	0.82	1
35.152	ESSEX-	KEARNY	230	230	SP/T	1.14	0.08	1
35.153	FRONT ST-	FANWOOD	230	230	SP/T	0.91		1
35.154	DEANS-	METUCHEN	230	230	SP/T	9.20	3.43	1
35.155	LUMBERTON-	COX'S CORNER	230	230	SP/T	4.33		1
35.156	TOSCO-	LINDEN VFT	230	230	SP/T	0.29		1
35.157	TRANSCO WILLIAMS-	ROSELAND	230	230	SP/T	0.17	—	1
35.158	HUNTERS GLEN	BRUNSWICK	230	230	SP/T	—	9.59	1
35.159	JACKSON	CEDAR GROVE	230	345	UG	4.36	—	1
35.160	NEWPORT-	HOBOKEN	230	230	UG	2.38	—	1
35.161	LUMBERTON-	COOKSTOWN	230	230	SP/T	18.05	—	1
35.162	LEONIA	BERGEN	230	230	UG	2.99	—	1
35.163	KITTATINNY-	NEWTON	230	230	SP/T	—	17.49	1
35.164	SEWAREN	METUCHEN	230	345	SP/T	—	6.84	2
35.165	SEWAREN-	RARITAN STEEL	230	230	UG	—	—	1
35.166	BRUNSWICK	DEVILS BROOK	230	230	SP/T	6.74		1
35.167	JERSEY CITY-	KEARNY	230	230	UG	0.42	—	1
35.168	JERSEY CITY-	KEARNY	230	230	UG	—	0.40	1
35.169	ROSELAND-	READINGTON [JCP&L]	230	230	SP/T	25.16	—	1
35.170	COX'S CORNER-	SILVER LAKE	230	230	SP/T	12.22	—	1
35.171	LINDEN VFT	WARINANCO	230	230	SP/T	2.32	—	1
35.172	CAMDEN-	CUTHBERT BLVD	230	230	UG	2.71		1
35.173	NORTH BERGEN	BERGEN	230	230	SP/T	2.14		1
35.174	LINDEN	LINDEN	230	230	SP/T	0.11	—	1
35.175	NEW MILFORD-	HILLSDALE	230	230	UG	5.91		1
36					TOTAL	1,867.93	357.42	250

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)	
								35.141
1590ACSR								35.142
1590ACSS								35.143
3500KCM CU.								35.144
1590ACSS/AW								35.145
2000KCM CU.								35.146
1590/1033.5ACSR/ACSS								35.147
1590ACSR								35.148
1590ACSR								35.149
1750/2500KCM CU.								35.150
1590ACSR								35.151
1590ACSR								35.152
1590ACSR								35.153
1590ACSR								35.154
1590ACSR								35.155
1590ACSR/ACSS/AW								35.156
1590ACSS/AW								35.157
1590ACSR/795ACSR								35.158
5000KCM CU.								35.159
2000/2500/5000KCM CU.								35.160
1590ACSR								35.161
2000KCM CU.								35.162
1590ACSR/ACSS								35.163
1590ACSR								35.164
1000ALUM								35.165
1590/795ACSR								35.166
1000KCM CU.								35.167
1000KCM CU.								35.168
1590ACSR								35.169
1590ACSR								35.170
1590ACSR								35.171
3000KCM CU.								35.172
1590ACSR								35.173
1590ACSR								35.174
3500KCM CU.								35.175
	115,771,488	6,984,945,266	7,100,716,754	20,810,339	38,099,496	6,567,139	65,476,974	36

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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)	LENGTH (Pole miles) On Structures of Another (g)	Number Of Circuits (h)
35.176	**230KV WHOLLY OWNED (BY PSE&G OR OTHERS)**							
35.177	BRUNSWICK	BENNETS LANE	230	230	SP/T	0.30	4.60	1
35.178	GLOUCESTER-	DEPTFORD	230	230	SP/T	0.84	2.38	2
35.179	ORANGE HEIGHT	WEST ORANGE	230	230	UG	2.76	—	1
35.180	ECHELON	COX'S CORNER	230	230	SP/T	—	5.95	1
35.181	DEANS-	WESTFIELD	230	230	SP/T	3.35	17.66	1
35.182	DEPTFORD-	THOROFARE	230	230	SP/T	1.84	4.29	2
35.183	SUNNYMEADE-	BRANCHBURG	230	230	SP/T	6.95	—	1
35.184	SEWAREN	METUCHEN -	230	230	SP/T	—	6.79	1
35.185	BENNETS LANE	BRANCHBURG	230	230	SP/T	0.16	12.02	1
35.186	HUDSON	NORTH BERGEN	230	230	SP/T	0.32	4.53	1
35.187	WESTFIELD	ALDENE	230	230	SP/T	2.71	—	1
35.188	SEWAREN-	METUCHEN	230	230	SP/T	6.74		1
35.189	MANSFIELD	BURLINGTON	230	230	SP/T	—	10.77	1
35.190	PENHORN	49TH STREET SUB.	230	230	SP/T	0.37	1.65	1
35.191	HOBOKEN	49TH STREET SUB.	230	230	UG	3.32	—	1
35.192	METUCHEN	SEWAREN	230	230	SP/T	0.28	6.43	1
35.193	ROSELAND-	CEDAR GROVE	230	230	SP/T	0.21	7.58	1
35.194	GLOUCESTER-	CAMDEN	230	230	UG	7.85	—	1
35.195	ATHENIA-	HARVEY	230	230	SP/T	—	0.39	1
35.196	WARD AVE	BURLINGTON	230	230	SP/T	—	16.45	1
35.197	ATHENIA-	BELLEVILLE	230	230	SP/T	0.64	5.22	1
35.198	SMITHBURG (JCP&L)	DEANS	230	230	SP/T	0.41	—	1
35.199	CAMDEN-	CUTHBERT BLVD.	230	230	UG	3.30	—	1
35.200	METUCHEN-	BRUNSWICK	230	345	SP/T	8.69	—	2
35.201	PLEASANT VALLEY-	ROCKTOWN	230	230	SP/T	2.53	—	1
35.202	**138KV WHOLLY OWNED (BY PSE&G OR OTHERS)**							
35.203	U.S. STEEL	TRENTON	138	230	SP/T	2.75	2.14	1
35.204	AMERICAN REFUEL-	FOUNDRY ST.	138	345	UG	1.29	—	1
35.205	ESSEX-	AMERICAN REFUEL	138	345	UG	0.24	—	1
35.206	Ward	Chesterfield	138	138	SP/T	0.19	—	1
35.207	DEY RD	SVC TO FORRESTAL	138	138	SP/T	2.22	—	1
35.208	NEWARK	FEDERAL SQUARE	138	138	UG	0.73	—	1
35.209	BERGEN SW	BERGEN GEN	138	138	SP/T	1.17		2
35.210	ESSEX-	NEWARK	138	138	UG	4.14	—	1
36					TOTAL	66.30	108.85	37

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)	
								35.176
1590ACSR								35.177
1033.5ACSS								35.178
3500KCM CU.								35.179
1590ACSR								35.180
1590ACSR/ACSS/AW								35.181
1033.5ACSS								35.182
1590ACSR/ACSS/AW								35.183
1590ACSR								35.184
1590ACSR/ACSS/AW								35.185
1590ACSR								35.186
1590ACSR/ACSS/AW								35.187
1590ACSR								35.188
397.5/1590ACSR/ACSS/AW								35.189
1590ACSR								35.190
2000/2500KCM CU.								35.191
1590ACSR								35.192
1590ACSR/ACSS/AW								35.193
3500KCM CU.								35.194
1590ACSR								35.195
1590ACSS								35.196
1590ACSR								35.197
1590ACSR								35.198
3500KCM CU.								35.199
1590ACSR								35.200
1590ACSS/AW								35.201
								35.202
1590ACSR								35.203
3000KCM CU.								35.204
3000KCM CU.								35.205
397.5 ACSR								35.206
397.5ACSR								35.207
2000KCM CU.								35.208
1590 ACSR/ACSS/AW								35.209
2000/2500/3000KCM CU. AL								35.210
	115,771,488	6,984,945,266	7,100,716,754	20,810,339	38,099,496	6,567,139	65,476,974	36

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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)
35.211	**138KV WHOLLY OWNED (BY PSE&G OR OTHERS)**							
35.212	ESSEX-	NEWARK	138	230	SP/T	0.12	—	1
35.213	ATHENIA-	FAIRLAWN	138	138	UG	8.89		1
35.214	ATHENIA-	KULLER RD	138	138	UG	1.83	—	1
35.215	BAYWAY-	FEDERAL SQUARE	138	345	UG	9.14	—	1
35.216	FOUNDRY ST-	NEWARK	138	138	UG	3.09	—	1
35.217	KULLER RD-	FAIRLAWN	138	345	UG	5.73	—	1
35.218	BERGEN#1-	FAIRLAWN	138	345	UG	11.22	—	1
35.219	NEWARK-	DOREMUS PL	138	138	UG	5.06	—	1
35.220	DOREMUS PL-	BAYWAY	138	138	UG	6	—	1
35.221	BERGEN-	EAST RUTHERFORD	138	138	UG	6.72	—	1
35.222	ATHENIA-	EAST RUTHERFORD	138	138	UG	3.76	—	1
35.223	L-AL 1/6	L-AL 1/2	138	138	SP/T	0.72	—	1
35.224	BURLINGTON-	COLONIAL	138	138	SP/T	—	—	1
35.225								
35.226								
35.227	Adj. double counting					(1,179.28)	(354.45)	
35.228								
35.229								
35.230								
35.231								
35.232								
35.233								
35.234								
35.235								
35.236								
35.237								
35.238								
35.239								
35.240								
35.241								
35.242								
35.243								
35.244								
35.245								
36					TOTAL	1,867.93	357.42	250

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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)	
								35.211
1590ACSR								35.212
1500/1250KCM CU.								35.213
2000KCM CU.								35.214
3000KCM CU.								35.215
2000KCM CU.								35.216
3000KCM CU.								35.217
3000KCM CU.								35.218
3000KCM CU.								35.219
3000KCM CU.								35.220
3000KCM CU.								35.221
3000KCM CU.								35.222
1590ACSR								35.223
1033.5/1590/397.5ACSS/								35.224
								35.225
								35.226
								35.227
								35.228
								35.229
								35.230
								35.231
								35.232
								35.233
								35.234
								35.235
								35.236
								35.237
								35.238
								35.239
								35.240
								35.241
								35.242
								35.243
								35.244
								35.245
	115,771,488	6,984,945,266	7,100,716,754	20,810,339	38,099,496	6,567,139	65,476,974	36

FOOTNOTE DATA

Schedule Page: 422 Line No.: 1 Column: a

Detailed information by line is provided on subsequent pages.

Schedule Page: 422 Line No.: 3 Column: e

Column (e)

SP -	Single Pole Steel
AT -	Aluminum Tower
ST -	Steel Tower
S/AT -	Steel/Aluminum Tower
RRO -	Railroad Overbuild
H -	H Frame Structure
HPFF -	High Pressure Fluid Filled - Pipe Type Cable
HPFG -	High Pressure Gas Filled - Pipe Type Cable
UCB -	Underground Conduit Bank
WP -	Wood Pole
XLPE -	Cross-Linked Polyethylene electric cable

Schedule Page: 422.1 Line No.: 35.002 Column: a

Jointly owned with Atlantic Electric, PEPCO, Philadelphia Electric, UGI, Metropolitan Edison, Delmarva P&L, Pennsylvania P&L, and Baltimore Gas & Electric. The respondent's ownership share is 23%.

Schedule Page: 422.1 Line No.: 35.003 Column: a

This line is jointly owned with Philadelphia Electric, Allegheny Electric, and Delmarva P&L. Respondent’s ownership share is 42.55%.

Schedule Page: 422.1 Line No.: 35.004 Column: a

This line is jointly owned with Philadelphia Electric, Allegheny Electric, and Delmarva P&L. Respondent’s ownership share is 42.55%.

Schedule Page: 422.1 Line No.: 35.005 Column: a

This line is jointly owned with Philadelphia Electric, Allegheny Electric, and Delmarva P&L. Respondent’s ownership share is 42.55%.

FOOTNOTE DATA

Schedule Page: 422.1 Line No.: 35.006 Column: a

This line is jointly owned with Philadelphia Electric, Allegheny Electric, and Delmarva P&L. Respondent's ownership share is 42.55%.

Schedule Page: 422.1 Line No.: 35.007 Column: a

This line is jointly owned with Philadelphia Electric, Allegheny Electric, and Delmarva P&L. Respondent's ownership share is 42.55%.

Schedule Page: 422.1 Line No.: 35.008 Column: a

Jointly owned with Consolidated Edison, Rockland Electric, and Orange & Rockland.

Schedule Page: 422.7 Line No.: 35.227 Column: f

Because the length of transmission lines is reported in a summary section and in the detail section, a credit is required to eliminate double counting.

Schedule Page: 422.7 Line No.: 35.227 Column: g

Because the length of transmission lines is reported in a summary section and in the detail section, a credit is required to eliminate double counting.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From	To		Type	Average Number per Miles	Present	Ultimate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	EAST WINDSOR (5022)	DEANS (5022)	0.00	SP/T	—	1	1
2	ESSEX (A-2227)	HUDSON (A-2227)	-0.13	SP/T	0.11	1	1
3	BURLINGTON (A-2279)	CAMDEN (A-2279)	0.00	SP/T	—	1	1
4	BURLINGTON (B-2280)	RANCOCAS (B-2280)	-0.03	SP/T	0.16	1	1
5	MEADOWS(C-2281)	NEW WASHINGTON (C-2281)	0.01	SP/T	—	1	1
6	FANWOOD (H-2286)	METUCHEN (H-2286)	-0.62	SP/T	0.13	1	1
7	MERCER (I-2261)	WF - COGEN (I-2261)	-0.30	SP/T	0.16	1	1
8	ROSELAND (I-2287)	FRONT STREET (I-2287)	-0.57	SP/T	0.15	1	1
9	ESSEX (J-2210)	NEWARK BAY COGEN. (J-2210)	-1.68	UG	0.12	1	1
10	KITTATINNY (K-1019)	BUSHKILL (K-1019)	0.00	SP/T	—	1	1
11	ATHENIA (K-2263)	CEDAR GROVE (K-2263)	0.00	SP/T	—	1	1
12	RANCOCAS (K-2342)	CINNAMINSON (K-2342)	0.06	SP/T	0.15	1	1
13	LEVITTOWN (M-2291)	CAMDEN (M-2291)	0.00	SP/T	—	1	1
14	MONTVILLE (N-2214)	NEWTON (N-2214)	-2.09	SP/T	0.23	1	1
15	HARVEY (O-2346)	NEW WASHINGTON (O-2346)	-0.01	SP/T	—	1	1
16	KEARNY (P-2216)	MEADOWS (P-2216)	-0.06	SP/T	0.09	1	1
17	NEWPORT (T-2220)	HOBOKEN (T-2220)	0.00	UG	—	1	1
18	HOBOKEN (T220-3-HOE)	HOBOKEN (T220-3-HOE)	0.00	UG	0.09	1	1
19	KITTATINNY (T-2298)	NEWTON (T-2298)	-0.37	SP/T	0.21	1	1
20	BRUNSWICK (V-2248)	BENNETS LANE (V-2248)	-0.06	SP/T	0.15	1	1
21	SEWAREN (X-2303)	METUCHEN (X-2303)	0.00	SP/T	—	1	1
22	PENHORN (Y-2225)	49TH STREET SUB. (Y-2225)	0.00	SP/T	—	1	1
23	SEWAREN (Y-2251)	METUCHEN (Y-2251)	0.00	SP/T	—	1	1
24	BAYWAY (K-1311)	FEDERAL SQUARE (K-1311)	0.00	UG	—	1	1
25	BURLINGTON (Y-1325)	COLONIAL (Y-1325)	-0.19	SP/T	0.09	1	1
26	VARIOUS (69KV)	VARIOUS (69KV)	31.21	WP	—	1	1
27	VARIOUS (69KV)	VARIOUS (69KV)	11.45	UCB	—	1	1
28	—	—	—	—	—	—	—
29	—	—	—	—	—	—	—
30	—	—	—	—	—	—	—
31	—	—	—	—	—	—	—
32	—	—	—	—	—	—	—
33	—	—	—	—	—	—	—
34	—	—	—	—	—	—	—
35	—	—	—	—	—	—	—
36	—	—	—	—	—	—	—
37	—	—	—	—	—	—	—
38	—	—	—	—	—	—	—
39	—	—	—	—	—	—	—
40	—	—	—	—	—	—	—
41	—	—	—	—	—	—	—
42	—	—	—	—	—	—	—
43			—	—	—	—	—
44	TOTAL		36.62		1.84	27	27

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating)	LINE COST						Line No.
Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	Construction	
(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	
2493	KCMIL	3 phase/1 conductor	500	—	6,567,435	11,972,512	—	18,539,947	Overground	1
1590	KCMIL	3 phase/1 conductor	230	—	—	—	—	—	Overground	2
1033.5/15	KCMIL	3 phase/1 conductor	230	2,880,090	—	8,380,923	—	11,261,013	Overground	3
1590/1033	KCMIL	3 phase/1 conductor	230	—	—	—	—	—	Overground	4
1590	KCMIL	3 phase/1 conductor	230	—	—	8,000,849	—	8,000,849	Overground	5
1590	KCMIL	3 phase/1 conductor	230	—	—	—	—	—	Overground	6
1590/795	KCMIL	3 phase/1 conductor	230	—	—	—	—	—	Overground	7
1590	KCMIL	3 phase/1 conductor	230	—	—	—	—	—	Overground	8
2000	KCMIL	3 phase/1 conductor	230	—	—	—	—	—	Underground	9
1590	KCMIL	3 phase/1 conductor	230	—	—	3,075,194	—	3,075,194	Overground	10
1590	KCMIL	3 phase/1 conductor	230	—	—	2,283,773	—	2,283,773	Overground	11
1033.5/15	KCMIL	3 phase/1 conductor	230	—	—	—	—	—	Overground	12
1590	KCMIL	3 phase/1 conductor	230	—	—	—	—	—	Overground	13
1590/2493	KCMIL	3 phase/1 conductor	230	—	—	—	—	—	Overground	14
1590	KCMIL	3 phase/1 conductor	230	—	—	—	—	—	Overground	15
1590	KCMIL	3 phase/1 conductor	230	—	—	—	—	—	Overground	16
2000/2500	KCMIL	3 phase/1 conductor	230	—	—	2,228,616	—	2,228,616	Underground	17
1000	KCMIL	3 phase/1 conductor	230	—	—	6,975,477	—	6,975,477	Underground	18
1590	KCMIL	3 phase/1 conductor	230	—	—	—	—	—	Overground	19
1590	KCMIL	3 phase/1 conductor	230	—	—	—	—	—	Overground	20
1590	KCMIL	3 phase/1 conductor	230	—	—	2,009,767	—	2,009,767	Overground	21
1590	KCMIL	3 phase/1 conductor	230	—	—	1,430,762	—	1,430,762	Overground	22
1590	KCMIL	3 phase/1 conductor	230	—	—	2,567,909	—	2,567,909	Overground	23
3000	KCMIL	3 phase/1 conductor	138	—	—	6,415,261	—	6,415,261	Underground	24
1033.5/15	KCMIL	3 phase/1 conductor	138	—	—	—	—	—	Overground	25
800	KCMIL	3 phase/1 conductor	69	—	28,184,210	172,649,454	—	200,833,664	Overground	26
1500	KCMIL	3 phase/1 conductor	69	5,059,279	—	—	—	5,059,279	Underground	27
—	—	—	—	—	—	—	—	—		28
—	—	—	—	—	—	—	—	—		29
—	—	—	—	—	—	—	—	—		30
—	—	—	—	—	—	—	—	—		31
—	—	—	—	—	—	—	—	—		32
—	—	—	—	—	—	—	—	—		33
—	—	—	—	—	—	—	—	—		34
—	—	—	—	—	—	—	—	—		35
—	—	—	—	—	—	—	—	—		36
—	—	—	—	—	—	—	—	—		37
—	—	—	—	—	—	—	—	—		38
—	—	—	—	—	—	—	—	—		39
—	—	—	—	—	—	—	—	—		40
—	—	—	—	—	—	—	—	—		41
—	—	—	—	—	—	—	—	—		42
—	—	—	—	—	—	—	—	—		43
				7,939,369	34,751,645	227,990,497		270,681,511		44

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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		VOLTAGE (in MVa)		
		Transmission or Distribution (b)	Attended or Unattended" (b-1)	Primary (c)	Secondary (d)	Tertiary (e)
1	PALISADES DIVISION					
2	Arcola, Paramus	Distribution	Unattended	26.40	4.15	—
3	Bergen Point, Bayone	Distribution	Unattended	26.40	4.15	—
4	Bergen County College	Distribution	Unattended	26.40	13.20	—
5	NJ Transit Meadow - CMS	Distribution	Unattended	230.00	55.00	—
6	NJ Transit Meadow - CMS	Distribution	Unattended	230.00	13.20	—
7	NJ Transit MMC	Distribution	Unattended	55.00	27.50	—
8	Constable Hook	Distribution	Unattended	26.40	13.20	—
9	Culver Avenue, Jersey City	Distribution	Unattended	26.40	4.15	—
10	Centex Towers	Distribution	Unattended	26.40	13.20	—
11	Fairview	Distribution	Unattended	26.40	4.15	—
12	Fort Lee	Distribution	Unattended	26.40	4.15	—
13	Fort Lee	Distribution	Unattended	26.40	13.20	—
14	Frank E. Rodgers	Distribution	Unattended	26.40	13.20	—
15	Garfield Ave., Jersey City	Distribution	Unattended	26.40	4.15	—
16	Harrison	Distribution	Unattended	26.40	4.15	—
17	Howell St, Jersey City	Distribution	Unattended	13.00	4.15	—
18	Little Ferry	Distribution	Unattended	26.40	13.20	—
19	Lodi	Distribution	Unattended	26.40	13.20	—
20	Mall, Paramus (Note 1)	Distribution	Unattended	26.40	13.20	—
21	Morgan Street, Jersey City	Distribution	Unattended	26.40	4.15	—
22	Polk Street, W. New York	Distribution	Unattended	26.40	4.15	—
23	Ridgewood	Distribution	Unattended	26.40	4.15	—
24	South Waterfront, Jersey City	Distribution	Unattended	26.40	13.20	—
25	West New York	Distribution	Unattended	26.40	4.15	—
26	Westwood	Distribution	Unattended	26.40	4.15	—
27	—			—	—	—
28	METROPOLITAN DIVISION			—	—	—
29	Allwood, Clifton	Distribution	Unattended	26.40	4.15	—
30	Belleville	Distribution	Unattended	26.40	4.15	—
31	Belmont, Garfield	Distribution	Unattended	26.40	13.20	—
32	Bloomfield	Distribution	Unattended	26.40	4.15	—
33	Bloomfield	Distribution	Unattended	26.40	13.20	—
34	Caldwell, Caldwell Boro	Distribution	Unattended	26.40	4.15	—
35	Caldwell, Caldwell Boro	Distribution	Unattended	26.40	13.20	—
36	Central Avenue, Newark	Distribution	Unattended	26.40	4.15	—
37	East Orange	Distribution	Unattended	26.40	4.15	—
38	Essex Switch	Distribution	Unattended	26.40	13.20	—
39	Fair Lawn	Distribution	Unattended	26.40	4.15	—
40	Federal Square, Newark	Distribution	Unattended	26.40	4.15	—
41	TOTAL Transmission Substations					
42	TOTAL Distribution Substations					
43	TOTAL Generation Substations					
44	TOTAL					

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
						1
24	3	—	—	—	—	2
27	3	—	—	—	—	3
19	2	—	—	—	—	4
100	5	—	—	—	—	5
54	2	—	—	—	—	6
45	9	—	—	—	—	7
15	2	—	—	—	—	8
20	4	—	—	—	—	9
28	4	—	—	—	—	10
20	3	—	—	—	—	11
27	3	—	—	—	—	12
9	1	—	—	—	—	13
9	1	—	—	—	—	14
27	3	—	—	—	—	15
36	4	—	—	—	—	16
12	2	—	—	—	—	17
12	2	—	—	—	—	18
6	1	—	—	—	—	19
12	2	—	—	—	—	20
27	3	—	—	—	—	21
36	3	1	—	—	—	22
27	3	—	—	—	—	23
9	1	—	—	—	—	24
27	3	—	—	—	—	25
24	3	—	—	—	—	26
—	—	—	—	—	—	27
—	—	—	—	—	—	28
18	2	—	—	—	—	29
18	2	—	—	—	—	30
17	2	—	—	—	—	31
36	4	—	—	—	—	32
6	1	—	—	—	—	33
12	2	—	—	—	—	34
6	1	—	—	—	—	35
27	3	—	—	—	—	36
48	4	—	—	—	—	37
0	0	1	—	—	—	38
18	3	—	—	—	—	39
18	2	—	—	—	—	40
						41
						42
						43
						44

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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		VOLTAGE (in MVa)		
		Transmission or Distribution (b)	Attended or Unattended" (b-1)	Primary (c)	Secondary (d)	Tertiary (e)
40.001	Fifteenth Street, Newark	Distribution	Unattended	26.40	4.15	—
40.002	Fifteenth Street, Newark	Distribution	Unattended	26.40	13.20	—
40.003	Getty Avenue, Clifton	Distribution	Unattended	26.40	4.15	—
40.004	Haledon	Distribution	Unattended	26.40	4.15	—
40.005	Ironbound	Distribution	Unattended	26.40	4.15	—
40.006	Irvington	Distribution	Unattended	26.40	4.15	—
40.007	Legion Place, Fair Lawn	Distribution	Unattended	26.40	4.15	—
40.008	Montclair	Distribution	Unattended	26.40	4.15	—
40.009	Mountain View, Wayne	Distribution	Unattended	26.40	13.20	—
40.010	Nevins Rd., Fairlawn	Distribution	Unattended	26.40	13.20	—
40.011	Ninteenth Ave., Newark	Distribution	Unattended	26.40	4.15	—
40.012	Ninteenth Ave., Newark	Distribution	Unattended	26.40	13.20	—
40.013	Newark Airport Breaker Station, Newark (Note 5)	Distribution	Unattended	—	—	—
40.014	Newark Switch	Distribution	Unattended	26.40	13.20	—
40.015	Norfolk Street, Newark	Distribution	Unattended	26.40	4.15	—
40.016	Nutley	Distribution	Unattended	26.40	4.15	—
40.017	Paterson	Distribution	Unattended	26.40	4.15	—
40.018	Port Street, Newark (Note 1)	Distribution	Unattended	26.40	13.20	—
40.019	South Orange	Distribution	Unattended	26.40	4.15	—
40.020	VanHouten Ave., Clifton	Distribution	Unattended	26.40	4.15	—
40.021	Waverly, Newark	Distribution	Unattended	26.40	4.15	—
40.022	West Orange	Distribution	Unattended	26.40	4.15	—
40.023				—	—	—
40.024	CENTRAL DIVISION			—	—	—
40.025	Albany Street, Bkr. Sta., New Bruns. (NOTE 5)	Distribution	Unattended	26.40	—	—
40.026	Avenel, Woodbridge	Distribution	Unattended	26.40	4.15	—
40.027	Bound Brook, Middlesex	Distribution	Unattended	26.40	4.15	—
40.028	Carteret	Distribution	Unattended	26.40	4.15	—
40.029	Clark, Clark	Distribution	Unattended	26.40	4.15	—
40.030	Cliff Road, Woodbridge	Distribution	Unattended	26.40	13.20	—
40.031	Cranford	Distribution	Unattended	26.40	4.15	—
40.032	Dayton, So. Brunswick	Distribution	Unattended	26.40	13.20	—
40.033	Deans Switch, S. Brunswick	Distribution	Unattended	26.40	4.15	—
40.034	Deans Switch, S. Brunswick	Distribution	Unattended	26.40	13.20	—
40.035	Edison	Distribution	Unattended	26.40	4.15	—
40.036	Edison	Distribution	Unattended	26.40	13.12	—
40.037	Elizabeth	Distribution	Unattended	26.40	4.15	—
40.038	Finderne, Bridgewater	Distribution	Unattended	26.40	4.15	—
40.039	First Street, Elizabeth	Distribution	Unattended	26.40	4.15	—
40.040	Franklin Sub	Distribution	Unattended	69.00	13.20	—
41	TOTAL Transmission Substations					
42	TOTAL Distribution Substations					
43	TOTAL Generation Substations					
44	TOTAL					

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
3	1	—	—	—	—	40.001
9	1	—	—	—	—	40.002
18	2	—	—	—	—	40.003
18	3	—	—	—	—	40.004
27	3	—	—	—	—	40.005
27	3	—	—	—	—	40.006
3	1	—	—	—	—	40.007
27	3	—	—	—	—	40.008
6	1	—	—	—	—	40.009
9	1	—	—	—	—	40.010
18	2	—	—	—	—	40.011
9	1	—	—	—	—	40.012
—	—	—	—	—	—	40.013
72	4	—	—	—	—	40.014
21	6	—	—	—	—	40.015
18	2	—	—	—	—	40.016
27	3	—	—	—	—	40.017
9	1	—	—	—	—	40.018
30	4	—	—	—	—	40.019
17	3	—	—	—	—	40.020
27	3	—	—	—	—	40.021
24	3	—	—	—	—	40.022
—	—	—	—	—	—	40.023
—	—	—	—	—	—	40.024
—	—	—	—	—	—	40.025
18	2	—	—	—	—	40.026
18	2	—	—	—	—	40.027
18	2	—	—	—	—	40.028
21	3	—	—	—	—	40.029
6	1	—	—	—	—	40.030
27	3	—	—	—	—	40.031
9	1	—	—	—	—	40.032
—	—	1	—	—	—	40.033
—	—	1	—	—	—	40.034
18	2	—	—	—	—	40.035
9	1	—	—	—	—	40.036
27	3	—	—	—	—	40.037
8	2	—	—	—	—	40.038
18	2	—	—	—	—	40.039
54	2	—	—	—	—	40.040
						41
						42
						43
						44

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Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (in MVa)		
		Transmission or Distribution (b)	Attended or Unattended" (b-1)	Primary (c)	Secondary (d)	Tertiary (e)
40.041	Hancock St., S. Plainfield	Distribution	Unattended	26.40	4.15	—
40.042	Harts Lane, E. Brunswick	Distribution	Unattended	69.00	13.20	—
40.043	Henry Street, Elizabeth	Distribution	Unattended	26.40	4.15	—
40.044	Keasbey, Woodbridge	Distribution	Unattended	26.40	4.15	—
40.045	Kenilworth	Distribution	Unattended	26.40	4.15	—
40.046	Lehigh Ave., Union	Distribution	Unattended	26.40	4.15	—
40.047	Mechanic St., Perth Amboy	Distribution	Unattended	26.40	4.15	—
40.048	Mechanic St., Perth Amboy	Distribution	Unattended	26.40	13.20	—
40.049	Menlo Park Breaker St., Edison (Note 5)	Distribution	Unattended	—	—	—
40.050	Mountainside	Distribution	Unattended	26.40	13.20	—
40.051	New Elizabeth Sub	Distribution	Unattended	69.00	4.15	—
40.052	Pleasant Street, Linden	Distribution	Unattended	26.40	4.15	—
40.053	Rahway	Distribution	Unattended	26.40	4.15	—
40.054	Raritan Valley, Somerville	Distribution	Unattended	26.40	4.15	—
40.055	Raritan Valley, Somerville	Distribution	Unattended	26.40	13.20	—
40.056	Roselle	Distribution	Unattended	26.40	4.15	—
40.057	Metuchen Switch	Distribution	Unattended	26.00	4.15	—
40.058	Union	Distribution	Unattended	26.40	4.15	—
40.059	—			—	—	—
40.060	SOUTHERN DIVISION			—	—	—
40.061	Audubon	Distribution	Unattended	26.40	4.15	—
40.062	Bordentown	Distribution	Unattended	26.40	4.15	—
40.063	Chauncey St., Trenton	Distribution	Unattended	26.40	4.15	—
40.064	Cherry Hill	Distribution	Unattended	26.40	4.15	—
40.065	Chester, Maple Shade	Distribution	Unattended	26.40	4.15	—
40.066	Collingswood	Distribution	Unattended	26.40	4.15	—
40.067	Fernwood, Ewing	Distribution	Unattended	26.40	13.20	—
40.068	Haddon Heights	Distribution	Unattended	26.40	4.15	—
40.069	Lamerton Road, Hamilton	Distribution	Unattended	26.40	13.20	—
40.070	Lawnside	Distribution	Unattended	69.00	13.20	—
40.071	Lawrence	Distribution	Unattended	69.00	13.20	—
40.072	Maple Shade	Distribution	Unattended	69.00	13.20	—
40.073	Monument Breaker Station (NOTE 5)	Distribution	Unattended	26.40	—	—
40.074	Medford	Distribution	Unattended	69.00	13.20	—
40.075	Mount Rose, Hopewell	Distribution	Unattended	69.00	13.20	—
40.076	Penns Neck, West Windsor	Distribution	Unattended	69.00	13.20	—
40.077	Pine Street, Camden	Distribution	Unattended	26.40	4.15	—
40.078	Princeton, Princeton Boro	Distribution	Unattended	26.40	4.15	—
40.079	Thirty-Second St., Camden	Distribution	Unattended	26.40	4.15	—
40.080	Village Road, W. Windsor	Distribution	Unattended	26.40	13.20	—
41	TOTAL Transmission Substations					
42	TOTAL Distribution Substations					
43	TOTAL Generation Substations					
44	TOTAL					

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.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
18	2	—	—	—	—	40.041
81	3	—	—	—	—	40.042
12	3	—	—	—	—	40.043
27	3	—	—	—	—	40.044
18	2	—	—	—	—	40.045
18	2	—	—	—	—	40.046
27	3	—	—	—	—	40.047
10	1	—	—	—	—	40.048
—	—	—	—	—	—	40.049
9	1	—	—	—	—	40.050
30	3	—	—	—	—	40.051
22	3	—	—	—	—	40.052
27	3	—	—	—	—	40.053
12	2	—	—	—	—	40.054
6	1	—	—	—	—	40.055
18	2	—	—	—	—	40.056
—	—	1	—	—	—	40.057
24	3	—	—	—	—	40.058
—	—	—	—	—	—	40.059
—	—	—	—	—	—	40.060
18	2	1	—	—	—	40.061
12	2	—	—	—	—	40.062
27	3	—	—	—	—	40.063
18	3	—	—	—	—	40.064
16	3	—	—	—	—	40.065
5	2	—	—	—	—	40.066
20	2	—	—	—	—	40.067
18	3	—	—	—	—	40.068
9	1	—	—	—	—	40.069
27	1	—	—	—	—	40.070
12	1	—	—	—	—	40.071
27	1	—	—	—	—	40.072
—	—	—	—	—	—	40.073
27	1	—	—	—	—	40.074
54	2	—	—	—	—	40.075
54	2	—	—	—	—	40.076
18	2	—	—	—	—	40.077
18	2	—	—	—	—	40.078
27	3	—	—	—	—	40.079
6	1	—	—	—	—	40.080
						41
						42
						43
						44

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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		VOLTAGE (in MVa)		
		Transmission or Distribution (b)	Attended or Unattended" (b-1)	Primary (c)	Secondary (d)	Tertiary (e)
40.081	Westmont, Haddon Twp.	Distribution	Unattended	26.40	4.15	—
40.082	TRANSMISSION			—	—	—
40.083	CENTRAL DIVISION			—	—	—
40.084	Adams, No. Brunswick	Transmission	Unattended	230.00	13.20	—
40.085	Aldene Switch, Cranford	Transmission	Unattended	230.00	26.40	11.00
40.086	Aldene Sub, Cranford	Transmission	Unattended	230.00	13.20	—
40.087	Bayway Switch, Elizabeth	Transmission	Unattended	345.00	26.40	13.00
40.088	Bayway Switch, Elizabeth	Transmission	Unattended	345.00	138.00	13.00
40.089	Bennetts Lane Sub	Transmission	Unattended	230.00	13.20	—
40.090	Bennetts Lane Switch	Transmission	Unattended	230.00	69.00	—
40.091	Branchburg Switch	Transmission	Unattended	500.00	230.00	13.00
40.092	Bridgewater Switch	Transmission	Unattended	230.00	69.00	—
40.093	Bridgewater Switch	Transmission	Unattended	230.00	26.40	11.00
40.094	Brunswick Switch, N. Brunswick	Transmission	Unattended	230.00	138.00	—
40.095	Brunswick Switch, N. Brunswick	Transmission	Unattended	230.00	69.00	—
40.096	Brunswick Switch, N. Brunswick	Transmission	Unattended	230.00	26.40	11.00
40.097	Brunswick Sub, N. Brunswick	Transmission	Unattended	230.00	13.20	—
40.098	Deans Switch, S. Brunswick	Transmission	Unattended	500.00	230.00	13.20
40.099	Deans Switch, S. Brunswick	Transmission	Unattended	230.00	69.00	—
40.100	Deans Switch, S. Brunswick	Transmission	Unattended	138.00	26.40	11.00
40.101	Doremus Sub	Transmission	Unattended	138.00	13.20	—
40.102	Fanwood Sub	Transmission	Unattended	230.00	13.20	—
40.103	Flagtown Switch Rack, Hillsboro (Note 5)	Transmission	Unattended	230.00	—	—
40.104	Front Street, Scotch Plains	Transmission	Unattended	69.00	4.15	—
40.105	Front Street, Scotch Plains	Transmission	Unattended	230.00	69.00	—
40.106	Fourteenth Street	Transmission	Unattended	69.00	26.40	—
40.107	Fourteenth Street	Transmission	Unattended	69.00	13.20	—
40.108	Greenbrook	Transmission	Unattended	230.00	69.00	—
40.109	Greenbrook	Transmission	Unattended	230.00	13.20	—
40.110	Kilmer Sub	Transmission	Unattended	230.00	13.20	—
40.111	Lafayette Road, Woodbridge	Transmission	Unattended	230.00	13.20	—
40.112	Lake Nelson Switch	Transmission	Unattended	230.00	69.00	—
40.113	Lake Nelson Sub	Transmission	Unattended	230.00	13.20	—
40.114	Linden Switch	Transmission	Unattended	138.00	26.40	11.00
40.115	Linden Switch	Transmission	Unattended	230.00	138.00	13.20
40.116	Linden Switch	Transmission	Unattended	345.00	230.00	13.20
40.117	Linden Switch	Transmission	Unattended	345.00	138.00	—
40.118	Meadow Road Sub	Transmission	Unattended	230.00	13.20	—
40.119	Metuchen Switch	Transmission	Attended	230.00	26.40	11.00
40.120	Metuchen Switch	Transmission	Attended	230.00	26.40	—
41	TOTAL Transmission Substations					
42	TOTAL Distribution Substations					
43	TOTAL Generation Substations					
44	TOTAL					

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
18	2	—	—	—	—	40.081
—	—	—	—	—	—	40.082
—	—	—	—	—	—	40.083
54	2	—	—	—	—	40.084
144	2	—	—	—	—	40.085
54	2	—	—	—	—	40.086
270	3	—	—	—	—	40.087
900	2	—	—	—	—	40.088
54	2	—	—	—	—	40.089
150	1	—	—	—	—	40.090
1,575	9	1	—	—	—	40.091
150	1	—	—	—	—	40.092
144	2	—	—	—	—	40.093
—	—	1	—	—	—	40.094
360	2	1	—	—	—	40.095
144	2	—	—	—	—	40.096
54	2	—	—	—	—	40.097
1,575	9	—	—	—	—	40.098
—	—	1	—	—	—	40.099
—	—	9	—	—	—	40.100
108	4	—	—	—	—	40.101
54	2	—	—	—	—	40.102
—	—	—	—	—	—	40.103
31	3	—	—	—	—	40.104
180	1	—	—	—	—	40.105
54	2	—	—	—	—	40.106
81	3	—	—	—	—	40.107
180	1	—	—	—	—	40.108
54	2	—	—	—	—	40.109
108	4	—	—	—	—	40.110
54	2	—	—	—	—	40.111
150	1	—	—	—	—	40.112
54	2	—	—	—	—	40.113
144	2	—	—	—	—	40.114
330	1	—	—	—	—	40.115
450	1	1	—	—	—	40.116
900	2	1	—	—	—	40.117
54	2	—	—	—	—	40.118
144	2	1	—	—	—	40.119
—	—	1	—	—	—	40.120
						41
						42
						43
						44

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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		VOLTAGE (in MVa)		
		Transmission or Distribution (b)	Attended or Unattended" (b-1)	Primary (c)	Secondary (d)	Tertiary (e)
40.121	Metuchen Switch	Transmission	Attended	230.00	138.00	—
40.122	Metuchen Switch	Transmission	Attended	230.00	13.20	—
40.123	Metuchen Switch	Transmission	Attended	69.00	13.20	—
40.124	Metuchen Switch	Transmission	Attended	69.00	26.00	—
40.125	Metuchen Switch	Transmission	Attended	69.00	4.15	—
40.126	Metuchen Switch	Transmission	Attended	230.00	26.00	11.00
40.127	Metuchen Switch	Transmission	Attended	230.00	13.00	13.00
40.128	Metuchen Switch	Transmission	Attended	138.00	13.20	—
40.129	Metuchen Switch	Transmission	Attended	138.00	69.00	—
40.130	Metuchen Switch	Transmission	Attended	345.00	26.40	13.20
40.131	Metuchen Switch	Transmission	Attended	345.00	13.20	—
40.132	Metuchen Switch	Transmission	Attended	230.00	69.00	—
40.133	Minue St Sub	Transmission	Unattended	230.00	13.20	—
40.134	Mountain Ave Sub	Transmission	Unattended	69.00	13.20	—
40.135	North Bridge St Sub	Transmission	Unattended	69.00	13.20	—
40.136	New Dover Sub	Transmission	Unattended	230.00	13.20	—
40.137	North Ave Sub	Transmission	Unattended	345.00	13.20	—
40.138	Pierson Ave Sub	Transmission	Unattended	230.00	13.20	—
40.139	Plainfield	Transmission	Unattended	69.00	4.15	—
40.140	Polhemus Lane Sub	Transmission	Unattended	230.00	13.20	—
40.141	Sand Hills Sub	Transmission	Unattended	69.00	13.20	—
40.142	Sewaren Switch, Woodbridge	Transmission	Unattended	230.00	26.40	11.00
40.143	Somerville Sub	Transmission	Unattended	230.00	13.20	—
40.144	South 2nd St., Plainfield	Transmission	Unattended	69.00	13.20	—
40.145	Springfield Road Sub	Transmission	Unattended	230.00	13.20	—
40.146	Springfield Road Sub	Transmission	Unattended	230.00	69.00	—
40.147	Stanley Terrace Sub	Transmission	Unattended	230.00	13.20	—
40.148	Stanley Terrace Sub	Transmission	Unattended	230.00	69.00	—
40.149	Sunnymeade Sub	Transmission	Unattended	230.00	13.20	—
40.150	Vauxhall Road Sub	Transmission	Unattended	69.00	13.20	—
40.151	Warinanco, Linden	Transmission	Unattended	230.00	13.20	—
40.152	Westfield Sub	Transmission	Unattended	230.00	13.20	13.20
40.153	Woodbridge	Transmission	Unattended	230.00	13.20	—
40.154	—			—	—	—
40.155	METRO DIVISION			—	—	—
40.156	Athenia, Clifton	Transmission	Unattended	230.00	138.00	—
40.157	Athenia, Clifton	Transmission	Unattended	138.00	26.40	11.00
40.158	Belleville Switch	Transmission	Unattended	230.00	26.40	—
40.159	Belleville Switch	Transmission	Unattended	230.00	69.00	—
40.160	Branchbrook Sub	Transmission	Unattended	69.00	13.20	—
41	TOTAL Transmission Substations					
42	TOTAL Distribution Substations					
43	TOTAL Generation Substations					
44	TOTAL					

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
—	—	1	—	—	—	40.121
—	—	3	—	—	—	40.122
—	—	3	—	—	—	40.123
—	—	2	—	—	—	40.124
—	—	1	—	—	—	40.125
—	—	1	—	—	—	40.126
—	—	1	—	—	—	40.127
—	—	1	—	—	—	40.128
—	—	1	—	—	—	40.129
—	—	1	—	—	—	40.130
—	—	2	—	—	—	40.131
—	—	2	—	—	—	40.132
54	2	—	—	—	—	40.133
29	3	—	—	—	—	40.134
81	3	—	—	—	—	40.135
54	2	—	—	—	—	40.136
54	2	—	—	—	—	40.137
54	2	—	—	—	—	40.138
31	3	—	—	—	—	40.139
54	2	—	—	—	—	40.140
54	2	—	—	—	—	40.141
216	3	—	—	—	—	40.142
54	2	—	—	—	—	40.143
54	2	—	—	—	—	40.144
54	2	—	—	—	—	40.145
180	1	—	—	—	—	40.146
54	2	—	—	—	—	40.147
180	1	—	—	—	—	40.148
108	4	—	—	—	—	40.149
54	2	—	—	—	—	40.150
54	2	—	—	—	—	40.151
78	2	—	—	—	—	40.152
81	3	—	—	—	—	40.153
—	—	—	—	—	—	40.154
—	—	—	—	—	—	40.155
660	2	—	—	—	—	40.156
349	10	—	—	—	—	40.157
160	4	—	—	—	—	40.158
180	1	—	—	—	—	40.159
54	2	—	—	—	—	40.160
						41
						42
						43
						44

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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		VOLTAGE (in MVa)		
		Transmission or Distribution (b)	Attended or Unattended" (b-1)	Primary (c)	Secondary (d)	Tertiary (e)
40.161	Cedar Grove Switch	Transmission	Unattended	230.00	69.00	—
40.162	Cedar Grove Sub	Transmission	Unattended	230.00	13.20	—
40.163	Clay Street, Newark	Transmission	Unattended	69.00	4.15	—
40.164	Clifton Sub	Transmission	Unattended	230.00	13.20	—
40.165	Cook Road Sub	Transmission	Unattended	230.00	13.20	—
40.166	Essex Switch, Newark	Transmission	Unattended	138.00	26.40	11.00
40.167	Essex Switch, Newark	Transmission	Unattended	230.00	138.00	—
40.168	Essex Switch, Newark	Transmission	Unattended	230.00	26.40	11.00
40.169	Fair Lawn Switch	Transmission	Unattended	230.00	138.00	—
40.170	Fair Lawn Switch	Transmission	Unattended	230.00	26.40	11.00
40.171	Fair Lawn Switch	Transmission	Unattended	138.00	69.00	—
40.172	Federal Square, Newark	Transmission	Unattended	138.00	4.15	—
40.173	Federal Square, Newark	Transmission	Unattended	138.00	69.00	—
40.174	Fortieth Street, Newark	Transmission	Unattended	69.00	4.15	—
40.175	Foundry Street, Newark	Transmission	Unattended	138.00	13.20	—
40.176	Foundry Street, Newark	Transmission	Unattended	138.00	69.00	—
40.177	Great Notch, Little Falls	Transmission	Unattended	69.00	4.15	—
40.178	Harvey Switch	Transmission	Unattended	230.00	69.00	—
40.179	Harvey Switch	Transmission	Unattended	69.00	13.20	—
40.180	Hawthorne	Transmission	Unattended	230.00	69.00	—
40.181	Hawthorne	Transmission	Unattended	230.00	13.20	—
40.182	Hinchmans Ave., Wayne	Transmission	Unattended	230.00	13.20	—
40.183	Hinchmans Ave., Wayne	Transmission	Unattended	230.00	69.00	—
40.184	Howe Ave, Passaic	Transmission	Unattended	69.00	13.20	—
40.185	Ironbound Sub	Transmission	Unattended	69.00	4.15	—
40.186	Jackson Road, Totowa	Transmission	Unattended	230.00	13.20	—
40.187	Jackson Road, Totowa	Transmission	Unattended	230.00	69.00	—
40.188	Kuller Road sub	Transmission	Unattended	69.00	13.20	—
40.189	Laurel Ave Sub	Transmission	Unattended	230.00	13.20	—
40.190	Livingston	Transmission	Unattended	230.00	13.20	—
40.191	Marion Drive Sub	Transmission	Unattended	230.00	13.20	—
40.192	McCarter Switching Station, Newark	Transmission	Unattended	230.00	26.40	11.00
40.193	McCarter Switching Station, Newark	Transmission	Unattended	230.00	69.00	—
40.194	Mclean Blvd., Paterson	Transmission	Unattended	69.00	4.15	—
40.195	North Park Street	Transmission	Unattended	69.00	4.15	—
40.196	New Washington, Belleville	Transmission	Unattended	230.00	13.20	—
40.197	Newark Airport Switch	Transmission	Unattended	345.00	26.40	13.20
40.198	Newark Switch	Transmission	Unattended	138.00	26.40	—
40.199	North Paterson, Paterson	Transmission	Unattended	69.00	4.15	—
40.200	Nye Ave Sub	Transmission	Unattended	69.00	13.20	—
41	TOTAL Transmission Substations					
42	TOTAL Distribution Substations					
43	TOTAL Generation Substations					
44	TOTAL					

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
330	2	—	—	—	—	40.161
54	2	—	—	—	—	40.162
31	3	—	—	—	—	40.163
54	2	—	—	—	—	40.164
108	4	—	—	—	—	40.165
—	—	3	—	—	—	40.166
660	2	—	—	—	—	40.167
216	3	—	—	—	—	40.168
240	1	—	—	—	—	40.169
216	3	1	—	—	—	40.170
360	2	—	—	—	—	40.171
36	3	1	—	—	—	40.172
180	1	—	—	—	—	40.173
21	2	—	—	—	—	40.174
54	2	—	—	—	—	40.175
180	1	—	—	—	—	40.176
21	2	—	—	—	—	40.177
360	2	—	—	—	—	40.178
54	2	—	—	—	—	40.179
180	1	—	—	—	—	40.180
54	2	—	—	—	—	40.181
54	2	—	—	—	—	40.182
150	1	—	—	—	—	40.183
54	2	—	—	—	—	40.184
30	3	—	—	—	—	40.185
108	4	1	—	—	—	40.186
180	1	—	—	—	—	40.187
54	2	—	—	—	—	40.188
108	4	—	—	—	—	40.189
54	2	—	—	—	—	40.190
54	2	—	—	—	—	40.191
216	3	—	—	—	—	40.192
180	1	—	—	—	—	40.193
31	3	—	—	—	—	40.194
31	3	—	—	—	—	40.195
54	2	—	—	—	—	40.196
270	3	—	—	—	—	40.197
270	3	1	—	—	—	40.198
31	3	—	—	—	—	40.199
54	2	—	—	—	—	40.200
						41
						42
						43
						44

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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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		VOLTAGE (in MVa)		
		Transmission or Distribution (b)	Attended or Unattended" (b-1)	Primary (c)	Secondary (d)	Tertiary (e)
40.201	Orange Heights Switch	Transmission	Unattended	230.00	69.00	—
40.202	Orange Heights Switch	Transmission	Unattended	69.00	4.15	—
40.203	Passaic Sub	Transmission	Unattended	69.00	4.15	—
40.204	Paterson Sub	Transmission	Unattended	69.00	26.40	—
40.205	Plauderville Sub	Transmission	Unattended	69.00	13.20	—
40.206	Port Street, Newark	Transmission	Unattended	69.00	13.20	—
40.207	Roseland Switch	Transmission	Unattended	500.00	230.00	13.20
40.208	South Paterson Sub	Transmission	Unattended	69.00	4.15	—
40.209	Toneys Brook Sub	Transmission	Unattended	69.00	4.15	—
40.210	Totowa, Totowa Boro	Transmission	Unattended	69.00	4.15	—
40.211	Warren Point, Fair Lawn	Transmission	Unattended	69.00	4.15	—
40.212	West Caldwell	Transmission	Unattended	230.00	13.20	—
40.213	West Orange Switch	Transmission	Unattended	230.00	26.40	11.00
40.214	—			—	—	—
40.215	PALISADES DIVISION	Transmission	Unattended	—	—	—
40.216	Bayonne Sub	Transmission	Unattended	138.00	13.20	—
40.217	Bayonne Sub	Transmission	Unattended	345.00	13.20	—
40.218	Bayonne Switch	Transmission	Unattended	345.00	138.00	—
40.219	Bayonne Switch	Transmission	Unattended	345.00	26.40	13.20
40.220	Bayonne Switch	Transmission	Unattended	230.00	26.40	11.00
40.221	Bayonne Switch	Transmission	Unattended	345.00	69.00	—
40.222	Bergen Switch, Ridgefield	Transmission	Unattended	230.00	26.40	11.00
40.223	Bergen Switch, Ridgefield	Transmission	Unattended	230.00	69.00	—
40.224	Bergen Switch, Ridgefield	Transmission	Unattended	230.00	138.00	13.20
40.225	Bergen Switch, Ridgefield	Transmission	Unattended	345.00	138.00	13.20
40.226	Bergen Switch, Ridgefield	Transmission	Unattended	345.00	230.00	13.20
40.227	Bergenfield	Transmission	Unattended	230.00	13.20	—
40.228	Bergenfield	Transmission	Unattended	230.00	69.00	—
40.229	Carlstadt	Transmission	Unattended	69.00	13.20	—
40.230	Carlstadt	Transmission	Unattended	69.00	26.40	—
40.231	Cliffs Sub, Englewood Cliffs	Transmission	Unattended	69.00	13.20	—
40.232	Dumont	Transmission	Unattended	69.00	4.15	—
40.233	Dumont	Transmission	Unattended	69.00	13.20	—
40.234	East Rutherford Switch	Transmission	Unattended	138.00	26.40	11.00
40.235	East Rutherford Switch	Transmission	Unattended	138.00	69.00	—
40.236	East Rutherford Sub	Transmission	Unattended	138.00	13.20	—
40.237	Englewood	Transmission	Unattended	69.00	4.15	—
40.238	Fairmount Sub	Transmission	Unattended	69.00	13.20	—
40.239	Greenville, Jersey City	Transmission	Unattended	69.00	4.15	—
40.240	Hackensack Sub	Transmission	Unattended	69.00	4.15	—
41	TOTAL Transmission Substations					
42	TOTAL Distribution Substations					
43	TOTAL Generation Substations					
44	TOTAL					

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
180	1	—	—	—	—	40.201
41	4	—	—	—	—	40.202
31	3	—	—	—	—	40.203
31	3	—	—	—	—	40.204
54	2	—	—	—	—	40.205
54	2	—	—	—	—	40.206
1,440	6	1	—	—	—	40.207
31	3	—	—	—	—	40.208
31	3	—	—	—	—	40.209
21	2	—	—	—	—	40.210
31	3	—	—	—	—	40.211
108	4	—	—	—	—	40.212
216	3	—	—	—	—	40.213
—	—	—	—	—	—	40.214
—	—	—	—	—	—	40.215
54	2	—	—	—	—	40.216
54	2	—	—	—	—	40.217
450	1	—	—	—	—	40.218
180	2	—	—	—	—	40.219
—	—	1	—	—	—	40.220
180	1	1	—	—	—	40.221
216	3	—	—	—	—	40.222
150	1	—	—	—	—	40.223
330	1	—	—	—	—	40.224
450	1	1	—	—	—	40.225
450	1	1	—	—	—	40.226
54	2	—	—	—	—	40.227
180	1	—	—	—	—	40.228
54	2	—	—	—	—	40.229
144	2	—	—	—	—	40.230
54	2	—	—	—	—	40.231
21	2	—	—	—	—	40.232
9	1	—	—	—	—	40.233
150	6	—	—	—	—	40.234
300	2	—	—	—	—	40.235
54	2	—	—	—	—	40.236
31	3	—	—	—	—	40.237
54	2	—	—	—	—	40.238
31	3	—	—	—	—	40.239
31	3	—	—	—	—	40.240
						41
						42
						43
						44

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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		VOLTAGE (in MVa)		
		Transmission or Distribution (b)	Attended or Unattended" (b-1)	Primary (c)	Secondary (d)	Tertiary (e)
40.241	Hasbrouck Heights	Transmission	Unattended	69.00	4.15	—
40.242	Hillsdale	Transmission	Unattended	230.00	26.40	—
40.243	Hillsdale	Transmission	Unattended	230.00	13.20	—
40.244	Hillsdale	Transmission	Unattended	230.00	69.00	—
40.245	Hoboken Sub	Transmission	Attended	230.00	13.20	13.20
40.246	Homestead, No. Bergen	Transmission	Unattended	230.00	13.20	—
40.247	Hudson Switch, Jersey City	Transmission	Unattended	345.00	230.00	—
40.248	Jersey City Switch	Transmission	Unattended	230.00	13.20	—
40.249	Kearny Sub	Transmission	Unattended	230.00	13.20	—
40.250	Kearny Switch	Transmission	Unattended	230.00	69.00	—
40.251	Kingsland Switch, North Arlington	Transmission	Unattended	230.00	69.00	—
40.252	Kingsland Sub, North Arlington	Transmission	Unattended	230.00	13.20	—
40.253	Leonia	Transmission	Unattended	230.00	13.20	—
40.254	Marion Switch, Jersey City	Transmission	Unattended	345.00	26.40	13.20
40.255	Maywood	Transmission	Unattended	230.00	13.20	—
40.256	Maywood	Transmission	Unattended	230.00	69.00	—
40.257	Madison Street, Hoboken	Transmission	Unattended	69.00	4.15	—
40.258	New Milford	Transmission	Unattended	230.00	13.20	—
40.259	New Milford Switch	Transmission	Unattended	230.00	69.00	—
40.260	Newport, Jersey City (Note 1)	Transmission	Unattended	230.00	13.20	—
40.261	North Bergen	Transmission	Unattended	230.00	13.20	—
40.262	Paramus	Transmission	Unattended	69.00	4.15	—
40.263	Penhorn Sub, Jersey City	Transmission	Unattended	230.00	13.20	—
40.264	Penhorn Sub, Jersey City	Transmission	Unattended	230.00	69.00	—
40.265	Ridgefield Sub	Transmission	Unattended	230.00	13.20	—
40.266	River Road, No. Bergen (Note 1)	Transmission	Unattended	69.00	13.20	—
40.267	Saddle Brook	Transmission	Unattended	230.00	13.20	—
40.268	So. Fifth Street	Transmission	Unattended	69.00	13.20	—
40.269	So. Mahwah Sw. Rack, Mahwah (Note 5)	Transmission	Unattended	345.00	—	—
40.270	So. Waterfront Switch	Transmission	Unattended	230.00	26.40	—
40.271	Spring Valley Rd., Paramus	Transmission	Unattended	69.00	13.20	—
40.272	Teaneck Sub	Transmission	Unattended	69.00	4.15	—
40.273	Tonnelle Ave., N. Bergen	Transmission	Unattended	69.00	4.15	—
40.274	Turnpike Sub	Transmission	Unattended	230.00	13.20	—
40.275	Union City, N. Bergen	Transmission	Unattended	69.00	4.15	—
40.276	Van Winkle Sub	Transmission	Unattended	69.00	4.15	—
40.277	Waldwick Sub	Transmission	Unattended	230.00	13.20	—
40.278	Waldwick Switch -	Transmission	Unattended	345.00	230.00	—
40.279	Waldwick Switch	Transmission	Unattended	345.00	230.00	13.20
40.280	—			—	—	—
41	TOTAL Transmission Substations					
42	TOTAL Distribution Substations					
43	TOTAL Generation Substations					
44	TOTAL					

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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
31	3	—	—	—	—	40.241
90	2	—	—	—	—	40.242
108	4	—	—	—	—	40.243
180	1	—	—	—	—	40.244
156	4	—	—	—	—	40.245
108	4	—	—	—	—	40.246
—	—	1	—	—	—	40.247
54	2	—	—	—	—	40.248
54	2	—	—	—	—	40.249
360	2	—	—	—	—	40.250
150	1	—	—	—	—	40.251
108	4	—	—	—	—	40.252
108	4	—	—	—	—	40.253
270	3	—	—	—	—	40.254
108	4	—	—	—	—	40.255
180	1	—	—	—	—	40.256
41	4	—	—	—	—	40.257
108	4	—	—	—	—	40.258
180	1	—	—	—	—	40.259
108	4	—	—	—	—	40.260
54	2	—	—	—	—	40.261
31	3	—	—	—	—	40.262
54	2	—	—	—	—	40.263
360	2	—	—	—	—	40.264
81	3	—	—	—	—	40.265
54	2	—	—	—	—	40.266
108	4	—	—	—	—	40.267
54	2	—	—	—	—	40.268
—	—	—	—	—	—	40.269
288	4	1	—	—	—	40.270
54	2	—	—	—	—	40.271
31	3	—	—	—	—	40.272
31	3	—	—	—	—	40.273
54	2	—	—	—	—	40.274
31	3	—	—	—	—	40.275
31	3	—	—	—	—	40.276
108	4	—	—	—	—	40.277
324	1	—	—	—	—	40.278
576	2	—	—	—	—	40.279
—	—	—	—	—	—	40.280
						41
						42
						43
						44

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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		VOLTAGE (in MVa)		
		Transmission or Distribution (b)	Attended or Unattended" (b-1)	Primary (c)	Secondary (d)	Tertiary (e)
40.281	SOUTHERN DIVISION	Transmission	Unattended	—	—	—
40.282	Beaver Brook, Bellmawr	Transmission	Unattended	230.00	13.20	—
40.283	Belle Meade Sub	Transmission	Unattended	69.00	26.40	—
40.284	Burlington Switch	Transmission	Unattended	230.00	26.40	11.00
40.285	Burlington Switch	Transmission	Unattended	230.00	69.00	—
40.286	Burlington Switch	Transmission	Unattended	138.00	13.00	—
40.287	Burlington Switch	Transmission	Unattended	230.00	138.00	—
40.288	Bustleton Sub	Transmission	Unattended	230.00	13.20	—
40.289	Camden Sub	Transmission	Unattended	69.00	13.20	—
40.290	Camden Sw., Pennsauken	Transmission	Unattended	230.00	69.00	—
40.291	Camden Sw., Pennsauken	Transmission	Unattended	230.00	26.40	11.00
40.292	Cinnaminson Sub	Transmission	Unattended	230.00	13.20	—
40.293	Cinnaminson Switch Rack (Note 5)	Transmission	Unattended	138.00	—	—
40.294	Clarksville, Lawrence	Transmission	Unattended	230.00	13.20	—
40.295	Clinton Sub	Transmission	Unattended	69.00	4.15	—
40.296	Crosswicks Sub	Transmission	Unattended	230.00	13.20	—
40.297	Cuthbert Sub	Transmission	Unattended	230.00	13.20	—
40.298	Cox's Corner, Evesham	Transmission	Unattended	230.00	13.20	—
40.299	Cox's Corner, Evesham (Note 5)	Transmission	Unattended	230.00	—	—
40.300	Delair, Pennsauken	Transmission	Unattended	69.00	4.15	—
40.301	Deptford Sub	Transmission	Unattended	230.00	13.20	—
40.302	Devils Brook Sub	Transmission	Unattended	230.00	13.20	—
40.303	East Riverton, Cinnaminson	Transmission	Unattended	69.00	4.15	—
40.304	East Riverton, Cinnaminson	Transmission	Unattended	69.00	13.20	—
40.305	Echelon, Cherry Hill	Transmission	Unattended	230.00	13.20	—
40.306	Ewing Sub	Transmission	Unattended	69.00	4.15	—
40.307	Gloucester Switch, Gloucester City	Transmission	Unattended	230.00	26.40	11.00
40.308	Gloucester Switch, Gloucester City	Transmission	Unattended	230.00	69.00	—
40.309	Hope Creek, Hancocks Bridge (Note 4 & Note 5)	Transmission	Unattended	500.00	230.00	13.20
40.310	Hopwell Switch	Transmission	Unattended	230.00	69.00	—
40.311	Hamilton Sub	Transmission	Unattended	69.00	4.15	—
40.312	Hilltop Sub	Transmission	Unattended	230.00	69.00	—
40.313	Hunters Glen Switch	Transmission	Unattended	230.00	69.00	—
40.314	Hunters Glen Switch	Transmission	Unattended	230.00	138.00	—
40.315	Kuser Road Sub	Transmission	Unattended	230.00	13.20	—
40.316	Lawnside	Transmission	Unattended	69.00	13.20	—
40.317	Lawrence Sub	Transmission	Unattended	230.00	13.20	—
40.318	Lawrence Switch	Transmission	Unattended	230.00	26.40	11.00
40.319	Lawrence Switch	Transmission	Unattended	230.00	69.00	—
40.320	Levittown Sub	Transmission	Unattended	230.00	13.20	—
41	TOTAL Transmission Substations					
42	TOTAL Distribution Substations					
43	TOTAL Generation Substations					
44	TOTAL					

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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
—	—	—	—	—	—	40.281
54	2	—	—	—	—	40.282
5	1	1	—	—	—	40.283
144	2	—	—	—	—	40.284
180	1	—	—	—	—	40.285
—	—	2	—	—	—	40.286
—	—	1	—	—	—	40.287
54	2	—	—	—	—	40.288
19	2	—	—	—	—	40.289
360	2	—	—	—	—	40.290
216	3	—	—	—	—	40.291
108	4	—	—	—	—	40.292
—	—	—	—	—	—	40.293
108	4	—	—	—	—	40.294
21	2	—	—	—	—	40.295
54	2	—	—	—	—	40.296
108	4	—	—	—	—	40.297
54	2	—	—	—	—	40.298
—	—	—	—	—	—	40.299
21	2	—	—	—	—	40.300
108	4	—	—	—	—	40.301
54	2	—	—	—	—	40.302
7	2	—	—	—	—	40.303
10	1	—	—	—	—	40.304
54	2	—	—	—	—	40.305
21	2	—	—	—	—	40.306
216	3	—	—	—	—	40.307
360	2	—	—	—	—	40.308
720	3	1	—	—	—	40.309
360	2	—	—	—	—	40.310
21	2	—	—	—	—	40.311
180	1	—	—	—	—	40.312
180	1	—	—	—	—	40.313
330	1	—	—	—	—	40.314
108	4	—	—	—	—	40.315
54	2	—	—	—	—	40.316
108	4	—	—	—	—	40.317
144	2	—	—	—	—	40.318
360	2	—	—	—	—	40.319
108	4	—	—	—	—	40.320
						41
						42
						43
						44

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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.
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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		VOLTAGE (in MVa)		
		Transmission or Distribution (b)	Attended or Unattended" (b-1)	Primary (c)	Secondary (d)	Tertiary (e)
40.321	Liberty Street Sub	Transmission	Unattended	69.00	4.15	—
40.322	Locust St, Camden	Transmission	Unattended	69.00	13.20	—
40.323	Lumberton	Transmission	Unattended	230.00	69.00	—
40.324	Lumberton	Transmission	Unattended	230.00	13.20	—
40.325	Maple Shade	Transmission	Unattended	69.00	13.20	—
40.326	Marlton Sub	Transmission	Unattended	230.00	13.20	—
40.327	Medford sub	Transmission	Unattended	69.00	13.20	—
40.328	Melrich Sub	Transmission	Unattended	69.00	13.20	—
40.329	Montgomery Sub	Transmission	Unattended	69.00	13.20	—
40.330	Mount Holly Sub	Transmission	Unattended	69.00	4.15	—
40.331	Mansfield Sub	Transmission	Unattended	230.00	13.20	—
40.332	Mount Laurel Sub	Transmission	Unattended	230.00	13.20	—
40.333	New State Street Sub	Transmission	Unattended	69.00	4.15	—
40.334	New Freedom Switch, Winslow (Note 2)	Transmission	Unattended	500.00	230.00	13.20
40.335	Nicholson Sub, Audubon Borough	Transmission	Unattended	69.00	13.20	—
40.336	Penns Neck Sub	Transmission	Unattended	69.00	13.20	—
40.337	Plainsboro Sub	Transmission	Unattended	230.00	13.20	—
40.338	Pleasant Valley, Hopewell (Note 5)	Transmission	Unattended	230.00	—	—
40.339	Rancocas, Delran	Transmission	Unattended	230.00	13.20	—
40.340	Riverside	Transmission	Unattended	69.00	4.15	—
40.341	Riverside	Transmission	Unattended	69.00	13.20	—
40.342	Runnemede Sub	Transmission	Unattended	69.00	13.20	—
40.343	Salem, Hancocks Bridge (Note 3 & Note 5)	Transmission	Unattended	500.00	0.00	—
40.344	Southampton Sub	Transmission	Unattended	69.00	13.00	—
40.345	Texas Ave Sub	Transmission	Unattended	69.00	13.00	—
40.346	Thorofare Sub	Transmission	Unattended	230.00	13.20	—
40.347	Trenton Switch, Hamilton	Transmission	Unattended	230.00	138.00	—
40.348	Trenton Switch, Hamilton	Transmission	Unattended	230.00	69.00	—
40.349	Trenton Switch, Hamilton	Transmission	Unattended	230.00	26.00	—
40.350	Ward Avenue Switch Rack, Chesterfield (Note 5)	Transmission	Unattended	138.00	—	—
40.351	Ward Avenue Switch Rack, Chesterfield	Transmission	Unattended	230.00	138.00	—
40.352	Whitehorse Sub	Transmission	Unattended	69.00	13.00	—
40.353	Whitehorse Switch	Transmission	Unattended	230.00	69.00	—
40.354	Woodbury Sub	Transmission	Unattended	69.00	4.00	—
40.355	Woodlynne Sub	Transmission	Unattended	69.00	4.00	—
40.356	Yardville Sub	Transmission	Unattended	230.00	13.00	—
40.357	T&D (Generation is not included)			—	—	—
40.358						
40.359						
40.360						
41	TOTAL Transmission Substations					
42	TOTAL Distribution Substations					
43	TOTAL Generation Substations					
44	TOTAL					

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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
21	2	—	—	—	—	40.321
54	2	—	—	—	—	40.322
300	2	—	—	—	—	40.323
54	2	—	—	—	—	40.324
54	2	—	—	—	—	40.325
108	4	—	—	—	—	40.326
27	1	—	—	—	—	40.327
54	2	—	—	—	—	40.328
29	3	—	—	—	—	40.329
31	3	—	—	—	—	40.330
54	2	—	—	—	—	40.331
54	2	—	—	—	—	40.332
31	3	—	—	—	—	40.333
2,100	12	—	—	—	—	40.334
54	2	—	—	—	—	40.335
27	1	—	—	—	—	40.336
54	2	—	—	—	—	40.337
—	—	—	—	—	—	40.338
54	2	—	—	—	—	40.339
7	2	—	—	—	—	40.340
10	1	—	—	—	—	40.341
54	2	—	—	—	—	40.342
—	—	—	—	—	—	40.343
54	2	—	—	—	—	40.344
54	2	—	—	—	—	40.345
54	2	—	—	—	—	40.346
202	1	—	—	—	—	40.347
180	1	—	—	—	—	40.348
216	3	—	—	—	—	40.349
0	0	—	—	—	—	40.350
20	1	1	—	—	—	40.351
54	2	—	—	—	—	40.352
180	1	—	—	—	—	40.353
31	3.00	—	—	—	—	40.354
31	3	—	—	—	—	40.355
54	2	—	—	—	—	40.356
39,722	—	—	—	—	—	40.357
						40.358
						40.359
						40.360
						41
						42
						43
						44

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

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		VOLTAGE (in MVa)		
		Transmission or Distribution (b)	Attended or Unattended" (b-1)	Primary (c)	Secondary (d)	Tertiary (e)
40.361	Reference Footnotes: Note 1					
40.362	Note 2					
40.363	Note 3					
40.364	Note 4					
40.365	Note 5					
40.366	Additional Comments					
40.367						
40.368						
40.369						
40.370						
40.371						
40.372						
40.373						
40.374						
40.375						
40.376						
40.377						
40.378						
40.379						
40.380						
40.381						
40.382						
40.383						
40.384						
40.385						
40.386						
40.387						
40.388						
40.389						
40.390						
40.391						
40.392						
40.393						
40.394						
40.395						
40.396						
40.397						
40.398						
40.399						
40.400						
41	TOTAL Transmission Substations					
42	TOTAL Distribution Substations					
43	TOTAL Generation Substations					
44	TOTAL					

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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
						40.361
						40.362
						40.363
						40.364
						40.365
						40.366
						40.367
						40.368
						40.369
						40.370
						40.371
						40.372
						40.373
						40.374
						40.375
						40.376
						40.377
						40.378
						40.379
						40.380
						40.381
						40.382
						40.383
						40.384
						40.385
						40.386
						40.387
						40.388
						40.389
						40.390
						40.391
						40.392
						40.393
						40.394
						40.395
						40.396
						40.397
						40.398
						40.399
						40.400
						41
						42
						43
						44

FOOTNOTE DATA

Schedule Page: 426.10 Line No.: 40.361 Column: a

Note 1:

Located on leased property:

- Mall, Paramus
- Newport, Jersey City
- River Road, No. Bergen
- Station, Newark
- Port Street, Newark

Schedule Page: 426.10 Line No.: 40.362 Column: a

Note 2:

New Freedom, Winslow Station is Co-owned with Atlantic City Electric Company 21.78%, and Respondent owns 78.22%. Expenses are shared on percentage ownership; amounts and accounts affected are not available.

Schedule Page: 426.10 Line No.: 40.363 Column: a

Note 3:

Salem, Hancocks Bridge Station is Co-owned with Atlantic City Electric Company 7.45%, PPL 7.45%, PECO 42.55%, and Respondent owns 42.55%. Expenses are shared on percentage of ownership; amounts and accounts affected are not available.

Schedule Page: 426.10 Line No.: 40.364 Column: a

Note 4:

Hope Creek, Hancocks Bridge Station is Co-owned with Atlantic City Electric Company 9.07% and Respondent owns 90.93%. Expenses are shared on percentage ownership; amounts and accounts affected are not available.

Schedule Page: 426.10 Line No.: 40.365 Column: a

Note 5:

Breaker Stations and Switch Racks may or may not have transformer equipment in the station to "increase capacity" (in MVA).

Schedule Page: 426.10 Line No.: 40.366 Column: a

Additional Comments:

- For Columns (c), (d) & (e) the units for Primary, Secondary & Tertiary VOLTAGE should be expressed in KV not MVA.
- For Column (b): D=Distribution; T=Transmission; U=Unattendaed; A=Attended
- Columns (i), (j) & (k) (Conversion Apparatus and Special Equipment) are not applicable to Respondent. Respondent does not own "special equipment such as rotary converters, rectifiers, condensers, etc. (for Increasing Capacity) and auxiliary equipment for Increasing Capacity" (in MVA).
- For column (f), "Capacity of substation (In Service)", the MVA value represents the base MVA not the top MVA.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Electric and Gas Company	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) *5/6/2026*	End of 2025/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Accounting Services	PSEG Services	923/416	15,365,674
3	Corporate Communications	PSEG Services	930.1/923/416/426/various	14,526,058
4	Corporate Development	PSEG Services	923/416/various	1,090,345
5	Corporate Secretary	PSEG Services	930.2/416	2,932,643
6	Corporate Services	PSEG Services	923/416/931/various	69,233,267
7	Corporate Strategy & Planning	PSEG Services	923/various	23,027,190
8	Cost of Capital as per Service Agreement	PSEG Services	923/416	16,836,098
9	Environmental Health and Safety	PSEG Services	923/various	13,615,378
10	General PSEG Management	PSEG Services	923/426/431/416	25,857,665
11	Governmental Affairs	PSEG Services	426/930.2/various	13,430,713
12	Human Resources	PSEG Services	923/416/various	25,352,734
13	Information Technology	PSEG Services	923/416/various	265,300,710
14	Internal Audit Services	PSEG Services	923/416	9,515,397
15	Law	PSEG Services	various	20,788,187
16	Procurement and Materials Management	PSEG Services	923/416/various	8,534,963
17	Treasury Management Services	PSEG Services	925/924/923/416/various	23,559,883
18	Construction support	PSEG Nuclear	101/107	40,256
18.1	Equipment maintenance/other	PSEG Power	various	3,834
19	**Total Provided by Affiliates**			**549,010,994**
20	**Non-power Goods or Services Provided by Affiliated**			
21	Project Support	PSEG Global	146/234	1,188,036
22	Equipment & Fleet maintenance/replacement;	PSEG Nuclear	146/234	706,122
23	Outage Support	PSEG Nuclear	146/234	191,918
24	Project Support	PSEG Nuclear	146/234	13,723
25	Environmental Support	PSEG Power	146/234	(8,407)
26	Fleet Maintenance; Gas Analysis;project and other support	PSEG Power	146/234	174,832
27	Project Support	PS Worryfree	146/234	12,116
28	Facility Support	PSEG Services	146/234	337,221
29	Fleet and Fleet Maintenance	PSEG Services	146/234	1,447,889
30	General Support	PSEG Services	146/234	140,809
31	Project Support	PSEG Services	146/234	1,357,291
32	Rent of Facilities	PSEG Services	146/234	387,746
33	Energy Monitoring System and other	PSEG ER&T	146/234	305,682
34				
35				
36				
37				
38				
39				
40				
41				
42	**Total Provided for Affiliates**			**6,254,978**

FOOTNOTE DATA

Schedule Page: 429 Line No.: 3 Column: g

"Various" includes charges to functionalized Operation and Maintenance Expense accounts; Customer Service and Informational; and Administrative and General Expense accounts within Electric Distribution, Gas Distribution Transmission, Capital and Third Party work.

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