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 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 Company of New Mexico	End of 2025/Q4

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KPMG LLP
Two Financial Center
60 South Street
Boston, MA 02111

Independent Auditors' Report

The Board of Directors
Public Service Company of New Mexico:

Opinion

We have audited the financial statements of Public Service Company of New Mexico (the Company), which comprise the balance sheets — regulatory basis as of December 31, 2025 and 2024, and the related statements of income — regulatory basis, retained earnings — regulatory basis, accumulated comprehensive income, comprehensive income, and hedging activities — regulatory basis and statement of cash flows — regulatory basis for the years then ended, and the related notes to the financial statements, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form No. 1 (FERC Form 1).

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position — regulatory basis of the Company as of December 31, 2025 and 2024, and the results of its operations — regulatory basis and its cash flows — regulatory basis thereof for the years then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Emphasis of Matter — Basis of Accounting

We draw attention to page 123.8 of the FERC Form 1, which describes the basis of accounting. As described on page 123.8 of the FERC Form 1, the financial statements are prepared by the Company on the basis of the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a basis of accounting other than U.S. generally accepted accounting principles, to meet the requirements of the Federal Energy Regulatory Commission. As a result, the financial statements may not be suitable for another purpose. Our opinion is not modified with respect to this matter.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, and for determining that the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases is an acceptable basis for the preparation of the financial statements in the circumstances. Management is also responsible for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

KPMG LLR a Delaware limited liability partnership and a member firm of
the KPMG global organization of independent member firms affiliated with
KPMG International Limited, a private English company limited by guarantee.

KPMG

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date that the financial statements are issued.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control related matters that we identified during the audit.

Restriction on Use

Our report is intended solely for the information and use of the board of directors and management of the Company and for filing with the Federal Energy Regulatory Commission and the New Mexico Public Regulation Commission and is not intended to be and should not be used by anyone other than these specified parties.

KPMG LLP

Boston, Massachusetts
April 17, 2026

New Mexico Jurisdictional Information
Year Ending December 31, 2025

Electric Company Name	Public Service Company of New Mexico
Address:	414 Silver Ave SW
Phone Number:	(505) 241-2289
Person Completing Form:	Todd Chenault

Customer Class	Residential	Other	Total
Number of Customers	498,772	59,795	558,567
KWH Sales (Thousands)	3,324,444	6,721,008	10,045,452
Gross Revenues	543,922,298	648,186,885	1,192,109,183
Avg. Annual KWH per Customer (1)	6,665	112,401	17,984
Avg. Annual Bill per Customer (2)	$1,090.52	$10,840.15	$2,134.23
Avg. Monthly Bill per Customer (3)	$90.88	$903.35	$177.85
Avg. Gross revenue per KWH sold (4)	0.1636	0.0964	0.1187

Direction for the completion of (1),(2),(3),(4):

(1) Divide KWH sales by number of customers.
(2) Divide gross revenues by number of customers.
(3) Divide (2) by 12 months.
(4) Divide gross revenues by KWH sales.

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

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

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy
Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

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

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

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

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

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

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

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

f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

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

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

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

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

V. Enter the month, day, and year for all dates. Use customary abbreviations. The **"Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

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

VII. For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

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

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

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the

above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

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.

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

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

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

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

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

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

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

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

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

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

IDENTIFICATION	
01 Exact Legal Name of Respondent Public Service Company of New Mexico	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)* 414 Silver Ave. SW, Albuquerque, NM 87102-3289	
05 Name of Contact Person Gerald R. Bischoff	06 Title of Contact Person VP, Corporate Controller
07 Address of Contact Person *(Street, City, State, Zip Code)* 414 Silver Ave. SW, Albuquerque, NM 87102-3289	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(505) 241-2245	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026

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)*
Gerald R. Bischoff		
02 Title VP, Corporate Controller	Gerald R. Bischoff	4/17/2026

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 (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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	None
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	
16	Electric Plant In Service	204-207	
17	Electric Plant Leased to Others	213	None
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	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)	None
24	Extraordinary Property Losses	230a	None
25	Unrecovered Plant and Regulatory Study Costs	230b	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	
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	
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	None
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/TROs	331	None
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	None
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	None
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	None
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	
64	Hydroelectric Generating Plant Statistics	406-407	None
65	Pumped Storage Generating Plant Statistics	408-409	None
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)
67	Energy Storage Operations (Large Plants)	414	None
67.1	Energy Storage Operations (Small Plants)	419-420	
68	Transmission Line Statistics Pages	422-423	
69	Transmission Lines Added During the Year	424-425	
70	Substations	426-427	
71	Transactions with Associated (Affiliated) Companies	429	
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☒ No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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.

   Gerald R. Bischoff, Vice President, Corporate Controller
   414 Silver Ave. SW, Albuquerque, NM 87102-3289

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.

   NM
   May 9, 1917

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.

   New Mexico
   Electric

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.

PNM is 100% owned by TXNM Energy, Inc. ("TXNM"), an investor-owned holding company. TXNM, formerly PNM Resources, Inc., ("PNMR") was incorporated in the state of New Mexico in 2000. In 2024, PNMR amended its Articles of Incorporation to change its name to TXNM Energy, Inc.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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)
1	Vice President, Corporate Controller	Gerald R. Bischoff	250,608
2			
3	Senior Vice President, Chief Financial Officer (termed 9/08/2025)	Elisabeth A. Eden	322,996
4			
5	Vice President, PNM Regulatory Senior Vice President, Chief Financial Officer (eff. 5/19/2025)	Henry E. Monroy	363,495
6			
7	Vice President, Chief Sustainability Officer (termed 7/23/2025)	Maureen Gannon	152,113
8			
9	Vice President, Treasurer and Strategy (eff. 5/19/2025)	Sabrina G. Greinel	273,770
10			
11	General Counsel, Senior Vice President Regulatory and Public Policy	Brian G. Iverson	463,846
12			
13	Vice President, Customer Operations	Kathleen Larese	253,978
14			
15	Vice President, Chief Information Officer	Sheila M. Mendez	297,359
16			
17	Vice President, NM Operations Principal, Operations and Special projects (eff. 7/19/2025)	Michael P. Mertz	368,152
18			
19	Senior Vice President, Corporate Services (eff. 4/14/2025)	Monique M. Jacobson	276,923
20			
21	Vice President, Chief Customer Officer (termed 4/28/2025)	Julie Rowey	90,865
22			
23	President, Chief Executive Officer	Joseph D. Tarry	839,462
24			
25	Vice President, Human Resources	Rebecca R. Teague	350,990
26			
27	Vice President, Operations and Engineering Senior Vice President, PNM Operations (eff. 7/19/2025)	Omni Warner	274,381
28			
29	Vice President, Integrated Planning Vice President, Integrated Planning and Transmission Development (eff. 7/19/2025)	Laurie Williams	283,455
30			
31	Executive Director, Investor Relations and Shareholder Services Vice President, Investor and Community Relations (eff. 5/19/2025)	Lisa Goodman	250,065
32			
33	Executive Director, Transmission and Distribution Vice President, PNM Operations and Engineering (eff. 7/19/2025)	Wesley Gray	234,911
34			
35	Executive Director, Financial Planning, Budget and Cost of Service Vice President, PNM Regulatory (eff. 5/19/2025)	Kyle Sanders	228,602
36			
37			
38			

Page 104, Row 1, Column (c)

Officer compensation amounts in column (c) are consolidated amounts for TXNM Energy, Inc.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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)
1	Patricia Collawn	Public Service Company of New Mexico
2	Chairman of the Board	414 Silver S.W.
3		Albuquerque, NM 87102-3289
4		
5	Elisabeth A. Eden	Public Service Company of New Mexico
6	Senior Vice President, Chief Financial Officer (termed 9/08/2025)	414 Silver S.W.
7		Albuquerque, NM 87102-3289
8		
9	Henry E. Monroy	Public Service Company of New Mexico
10	Senior Vice President, Chief Financial Officer (eff. 5/19/2025)	414 Silver S.W.
11		Albuquerque, NM 87102-3289
12		
13	Michael P. Mertz	Public Service Company of New Mexico
14	Senior Vice President, NM Operations (through 7/18/2025)	414 Silver S.W.
15		Albuquerque, NM 87102-3289
16		
17	Monique M. Jacobson	Public Service Company of New Mexico
18	Senior Vice President, Corporate Services	414 Silver S.W.
19		Albuquerque, NM 87102-3289
20		
21	Joseph D. Tarry	Public Service Company of New Mexico
22	President, Chief Executive Officer	414 Silver S.W.
23		Albuquerque, NM 87102-3289
24		
25		
26		
27		
28		
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30		
31	Note: Public Service Company of New Mexico does not have	
32	an Executive Committee	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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	FERC Electric Tariff, Volume 6, Att. H	ER26-1365-000
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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	20260130-5601	01/30/2026	ER26-1365-000	2025 Annual Update	FERC Electric Tariff, Volume 6, Att. H
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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.

Item 1 - PNM holds long-term, non-exclusive franchise agreements for its electric retail operations, with varying expiration dates. These franchise agreements allow the utility to access public rights-of-way for placement of its electric facilities. Franchise agreements may expire or be subject to negotiation in some areas PNM serves. Because PNM remains obligated under New Mexico state law to provide service to customers in these areas, the expiration of a franchise agreement should not have a material adverse impact. The Albuquerque, Rio Rancho, Los Lunas, and Santa Fe metropolitan areas accounted for 41.3%, 8.5%, 5.7% and 5.9% of PNM's 2025 revenues and no other franchise area represents more than 5%. PNM also earns revenues from its electric retail operations in its service areas that do not require franchise agreements.

Item 2 - On May 18, 2025, TXNM, Parent, and Merger Sub, entered into the Merger Agreement, pursuant to which Merger Sub will merge with and into TXNM, with TXNM surviving the Merger as a direct wholly-owned subsidiary of Parent. Parent and Merger Sub are affiliates of Blackstone Infrastructure. For additional information see Footnote 22 on pages 123.103-123.104.

Item 3 - None

Item 4 - Refer to Footnote 8 on page 123.39 for information regarding leases.

Item 5 - None

Item 6 - At December 31, 2025, PNM had a shelf registration statement, which was set to expire in May 2026, with capacity for the issuance of up to $650.0 million of SUNs. On February 20, 2026, PNM filed a post-effective amendment to the registration statement to deregister any and all securities that remained unsold, effectively terminating all offerings of the securities pursuant to the registration statement.

On November 10, 2025, PNM entered into the $120.0 million term loan agreement ("PNM November 2025 Term Loan"), among PNM, the lenders party thereto and U.S. Bank National Association, as administrative agent. PNM used the proceeds of the PNM November 2025 Term Loan to partially repay borrowings under the PNM 2024 Term Loan. The PNM November 2025 Term Loan bears interest at a variable rate, which was 4.67% at December 31, 2025, and must be repaid on or before May 10, 2027.

On July 31, 2025, PNM entered into an agreement (the "PNM July 2025 Note Purchase Agreement") with institutional investors for the sale and issuance of $350.0 million aggregate principal amount in two series of SUNs (the "PNM July 2025 SUNs") offered in private placement transactions. PNM issued $200.0 million at 5.47%, due July 31, 2031, and another $150.0 million at 6.03%, due July 31, 2036. PNM used the proceeds from the PNM July 2025 SUNs to repay the PNM $250.0 million SUNs and for general corporate purposes. The PNM July 2025 Note Purchase Agreement includes customary covenants. In the event of a change of control, PNM will be required to offer to prepay the PNM July 2025 SUNs at par. Although there are customary change of control provisions in the PNM debt agreements, the change of control provisions in the agreements, including the PNM July 2025 Note Purchase Agreement, will not be triggered by the closing of the Merger. PNM has the right to redeem any or all of the PNM July 2025 SUNs prior to their maturities, subject to the payment of a customary make-whole premium (NMPRC Case No 25-00012-UT).

On July 25, 2025, PNM amended the $40.0 million unsecured revolving credit facility (the "PNM New Mexico Credit Facility") to, among other things, extend the maturity to May 31, 2030. The revised agreement is with six participating lenders which are all banks that have a significant presence or are headquartered in New Mexico. The PNM New Mexico Credit Facility contains covenants and conditions similar to those in the PNM Revolving Credit Facility defined below (NMPRC Case No. 25-00012-UT).

On April 23, 2025, PNM entered into an agreement (the "PNM April 2025 Note Purchase Agreement") with institutional investors for the sale and issuance of $300.0 million aggregate principal amount in two series of SUNs (the "PNM April 2025 SUNs") offered in private placement transactions. PNM issued $125.0 million of the PNM April 2025 SUNs at 5.75%, due June 1, 2032, and another $175.0 million at 6.13%, due June 1, 2037. PNM used proceeds from the PNM April 2025 SUNs for the repayment of existing indebtedness, funding of capital expenditures, and general corporate purposes. The PNM April 2025 Note Purchase Agreement includes customary covenants. In the event of a change of control, PNM will be required to offer to prepay the PNM April 2025 SUNs at par. Although there are customary change of control provisions in the PNM debt agreements, the change of control provisions in the agreements, including the PNM April 2025 Note Purchase Agreement, are not triggered by the closing of the Merger. PNM has the right to redeem any or all of the PNM April 2025 SUNs prior to their maturities, subject to payment of a customary make-whole premium (NMPRC Case No 25-00012-UT).

On April 15, 2025, PNM filed with the NMPRC its Statement with Respect to Short-Term Securities. The Statement set out PNM's financing plan relating to its issuance, assumption or guaranty of short-term securities in an amount up to $1.1 billion during the period of May 1, 2025 through April 30, 2026.
On February 3, 2025, PNM filed an application with the NMPRC docketed as Case No. 25-00012-UT to obtain NMPRC approval to amend and extend its PNM New Mexico Credit Facility and to issue up to $730.0 million of long-term debt to fund

capital expenditures and fund and refinance other lawful obligations and requirements. This amount includes refinancing two series of notes maturing on May 15, and August 1, 2025 with the combined principal amount of $354.0 million. PNM received approval on March 6, 2025 for its application, and the approved transactions were completed subsequently.

On January 21, 2025, PNM entered into a $195.0 million term loan agreement (the "PNM January 2025 Term Loan"), among PNM, the lenders party thereto, and Canadian Imperial Bank of Commerce, New York Branch, as administrative agent. PNM used the proceeds of the PNM January2025 Term Loan to repay borrowings under the PNM Revolving Credit Facility, the PNM New Mexico Credit Facility, and for general corporate purposes. The PNM January 2025 Term Loan bears interest at a variable rate, which was 4.73% at December 31, 2025, and must be repaid on or before July 21, 2026. PNM has a revolving credit financing capacity of $400.0 million under the PNM Revolving Credit Facility. The revolving credit facility was authorized by NMPRC case number 10-00269-UT. On April 1, 2024, PNM entered into a Seventh Amendment and Restatement of Credit Agreement amending and restating its $400.0 million revolving credit agreement,among PNM, the lenders party thereto and Wells Fargo Bank, National Association as administrative agent and extending the maturities to maturity to March 30, 2029 and with two one-year extension options that if exercised, would extend the maturity to March 2031. On December 19, 2025, PNM exercised the first of the two one-year extension options, extending the maturity of the credit agreement to March 29, 2030. One lender in the revolving credit facility failed to agree to the extension. As a result, effective March 30, 2029, the PNM Revolving Credit Facility capacity will adjust to $354.1 million. The facility contains a financial covenant that requires the maintenance of debt-to-capitalization ratio of less than or equal to 65%. (NMPRC Case No. 24-00042-UT)

See Note 7 to the Consolidated Financial Statements on page 123.26.

Item 7 - None

Item 8 - PNM's annual merit award program, for non-union employees, recognized individual employee performance based on established performance targets in the previous calendar year. The merit awards were effective March 14, 2026 and the average award was approximately 3.87% of base salary. In addition, PNM awarded union employees a 5.0% base salary increase in accordance with the Collective Bargaining Agreement effective May 1, 2026.

Item 9 - See Notes 16 and 17 to Consolidated Financial Statements on pages 123.70 and 123.83.

Item 10 - None

Item 11 - (Reserved)

Item 12 - No annual report is issued.

Item 13 - The following title changes were effective May 19, 2025: Henry E. Monroy, Senior Vice President and Chief Financial Officer; Monique M. Jacobson, Senior Vice President, Corporate Services; Kyle T. Sanders, Vice President, Regulatory; Sabrina G. Greinel, Vice President, Treasurer and Strategy.

The following title changes were effective July 19,2025: Omni B. Warner, Senior Vice President, PNM Operations; Laurie Williams, Senior Vice President, PNM Integrated Planning and Transmission Development

Michael Mertz, Senior Vice President, NM Operations, resigned as an officer of PNM effective July 19, 2025. Maureen Gannon, Vice President and Chief Sustainability Officer, retired from PNM effective July 23, 2025.

Elisabeth A. Eden, Senior Vice President, Finance (former Senior Vice President and Chief Financial Officer) retired effective September 8, 2025.

Item 14 - Not applicable.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	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 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	7,391,526,043	7,085,933,210
3	Construction Work in Progress (107)	200-201	370,820,525	328,885,931
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		7,762,346,568	7,414,819,141
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,409,592,573	2,281,617,117
6	Net Utility Plant (Enter Total of line 4 less 5)		5,352,753,995	5,133,202,024
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202-203	45,732,717	40,402,115
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		657,172	657,172
9	Nuclear Fuel Assemblies in Reactor (120.3)		58,259,814	59,739,890
10	Spent Nuclear Fuel (120.4)		—	—
11	Nuclear Fuel Under Capital Lease (120.6)		—	—
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	27,953,207	28,245,381
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		76,696,496	72,553,796
14	Net Utility Plant (Enter Total of lines 6 and 13)		5,429,450,491	5,205,755,820
15	Utility Plant Adjustments (116)		(78,568,025)	(79,780,946)
16	Gas Stored Underground - Noncurrent (117)		—	—
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		98,532	98,532
19	(Less) Accum. Prov. for Depr. and Amort. (122)		2,653	2,653
20	Investments in Associated Companies (123)		—	—
21	Investment in Subsidiary Companies (123.1)	224-225	1,724,623	1,724,623
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	—	—
24	Other Investments (124)		—	—
25	Sinking Funds (125)		—	—
26	Depreciation Fund (126)		—	—
27	Amortization Fund - Federal (127)		—	—
28	Other Special Funds (128)		505,956,312	475,707,986
29	Special Funds (Non Major Only) (129)		34,605,959	30,566,838
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)		542,382,773	508,095,326
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		—	—
35	Cash (131)		—	2,678,779
36	Special Deposits (132-134)		—	—
37	Working Fund (135)		18,725	18,830
38	Temporary Cash Investments (136)		—	—
39	Notes Receivable (141)		—	—
40	Customer Accounts Receivable (142)		117,304,078	97,330,447
41	Other Accounts Receivable (143)		29,344,707	20,604,240
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,394,245	1,398,086
43	Notes Receivable from Associated Companies (145)		8,719,312	8,819,312
44	Accounts Receivable from Assoc. Companies (146)		8,911,052	551,380
45	Fuel Stock (151)	227	1,090,377	1,095,055
46	Fuel Stock Expenses Undistributed (152)	227	—	—
47	Residuals (Elec) and Extracted Products (153)	227	—	—
48	Plant Material and Operating Supplies (154)	227	143,336,170	140,270,316
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 12/31 (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)		18,501,620	14,746,222
58	Advances for Gas (166-167)		—	—
59	Interest and Dividends Receivable (171)		4,047,303	3,519,812
60	Rents Receivable (172)		—	—
61	Accrued Utility Revenues (173)		48,524,039	52,982,600
62	Miscellaneous Current and Accrued Assets (174)		13	100,116
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)		378,403,151	341,319,023
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		12,181,509	10,137,390
70	Extraordinary Property Losses (182.1)	230a	—	—
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	—	—
72	Other Regulatory Assets (182.3)	232	505,692,662	550,470,990
73	Prelim. Survey and Investigation Charges (Electric) (183)		37,073,003	33,221,232
74	Preliminary Natural Gas Survey and Investigation Charges (183.1)		—	—
75	Other Preliminary Survey and Investigation Charges (183.2)		—	—
76	Clearing Accounts (184)		(40,593)	(43,374)
77	Temporary Facilities (185)		—	—
78	Miscellaneous Deferred Debits (186)	233	192,902,172	171,102,091
79	Def. Losses from Disposition of Utility Plt. (187)		—	—
80	Research, Devel. and Demonstration Expend. (188)	352-353	—	—
81	Unamortized Loss on Reacquired Debt (189)		4,101,049	4,492,148
82	Accumulated Deferred Income Taxes (190)	234	239,762,959	264,349,945
83	Unrecovered Purchased Gas Costs (191)		—	—
84	Total Deferred Debits (lines 69 through 83)		991,672,761	1,033,730,422
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		7,263,341,151	7,009,119,645

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 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	195,588,995	195,588,995
3	Preferred Stock Issued (204)	250-251	11,529,299	11,529,299
4	Capital Stock Subscribed (202,205)		—	—
5	Stock Liability for Conversion (203, 206)		—	—
6	Premium on Capital Stock (207)		456,815,703	456,815,703
7	Other Paid-In Capital (208-211)	253	1,093,672,591	970,372,591
8	Installments Received on Capital Stock (212)	252	—	—
9	(Less) Discount on Capital Stock (213)	254	—	—
10	(Less) Capital Stock Expense (214)	254b	19,859,236	19,859,236
11	Retained Earnings (215, 215.1, 216)	118-119	697,381,328	610,280,237
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	—	—
13	(Less) Reacquired Capital Stock (217)	250-251	—	—
14	Noncorporate Proprietorship (Non-major only) (218)		—	—
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(25,702,764)	(75,707,581)
16	Total Proprietary Capital (lines 2 through 15)		2,409,425,916	2,149,020,008
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	2,225,345,000	1,929,345,000
19	(Less) Reacquired Bonds (222)	256-257	—	—
20	Advances from Associated Companies (223)	256-257	—	—
21	Other Long-Term Debt (224)	256-257	315,000,000	200,000,000
22	Unamortized Premium on Long-Term Debt (225)		—	—
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		—	40,541
24	Total Long-Term Debt (lines 18 through 23)		2,540,345,000	2,129,304,459
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		107,986,504	263,963,323
27	Accumulated Provision for Property Insurance (228.1)		—	—
28	Accumulated Provision for Injuries and Damages (228.2)		3,774,425	3,116,554
29	Accumulated Provision for Pensions and Benefits (228.3)		6,736,324	22,066,882
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)		254,352,933	243,662,443
35	Total Other Noncurrent Liabilities (lines 26 through 34)		372,850,186	532,809,202
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		178,800,000	363,800,000
38	Accounts Payable (232)		151,242,217	124,736,171
39	Notes Payable to Associated Companies (233)		—	—
40	Accounts Payable to Associated Companies (234)		19,648,834	16,892,846
41	Customer Deposits (235)		6,892,716	6,532,988
42	Taxes Accrued (236)	262-263	8,034,021	3,169,122
43	Interest Accrued (237)		27,739,818	19,992,907
44	Dividends Declared (238)		132,011	132,011
45	Matured Long-Term Debt (239)		—	—

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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 12/31 (d)
46	Matured Interest (240)		—	—
47	Tax Collections Payable (241)		13,131,005	12,061,786
48	Miscellaneous Current and Accrued Liabilities (242)		38,872,789	96,369,368
49	Obligations Under Capital Leases-Current (243)		14,677,578	17,853,345
50	Derivative Instrument Liabilities (244)		—	5,737,494
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)		459,170,989	667,278,038
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		68,045,973	79,154,899
57	Accumulated Deferred Investment Tax Credits (255)	266-267	80,898,636	81,068,074
58	Deferred Gains from Disposition of Utility Plant (256)		—	—
59	Other Deferred Credits (253)	269	131,761,892	143,963,851
60	Other Regulatory Liabilities (254)	278	240,971,162	298,017,217
61	Unamortized Gain on Reacquired Debt (257)		—	—
62	Accum. Deferred Income Taxes-Accel. Amort. (281)	272-277	1,966,958	1,970,686
63	Accum. Deferred Income Taxes-Other Property (282)		650,642,183	573,991,039
64	Accum. Deferred Income Taxes-Other (283)		307,262,256	352,542,172
65	Total Deferred Credits (lines 56 through 64)		1,481,549,060	1,530,707,938
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54, and 65)		7,263,341,151	7,009,119,645

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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 (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,457,281,533	1,354,290,003	—	—
3	Operating Expenses					
4	Operation Expenses (401)	320-323	959,566,470	775,260,766	—	—
5	Maintenance Expenses (402)	320-323	71,517,702	58,504,460	—	—
6	Depreciation Expense (403)	336-337	206,700,423	175,173,693	—	—
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	619,089	637,302	—	—
8	Amort. & Depl. Of Utility Plant (404-405)	336-337	—	11,735,700	—	—
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	1,418,021	1,707,827	—	—
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		—	—	—	—
11	Amort. of Conversion Expenses (407)		—	—	—	—
12	Regulatory Debits (407.3)		17,193,753	16,653,815	—	—
13	(Less) Regulatory Credits (407.4)		1,401,137	1,656,841	—	—
14	Taxes Other Than Income Taxes (408.1)	262-263	55,703,007	49,008,459	—	—
15	Income Taxes - Federal (409.1)	262-263	(19,743,037)	(6,209,687)	—	—
16	- Other (409.1)	262-263	(4,022,039)	(5,490,249)	—	—
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	318,155,938	299,429,096	—	—
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	310,208,021	274,904,269	—	—
19	Investment Tax Credit Adj. - Net (411.4)	266	(169,438)	7,224,165	—	—
20	(Less) Gains from Disp. Of Utility Plant (411.6)		152,204	—	—	—
21	Losses from Disp. Of Utility Plant (411.7)		—	—	—	—
22	(Less) Gains from Disposition of Allowances (411.8)		11	22	—	—
23	Losses from Disposition of Allowances (411.9)		—	—	—	—
24	Accretion Expense (411.10)		11,049,380	10,429,222	—	—
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24.2)		1,306,227,896	1,117,503,437	—	—
26	Net Util Oper Inc (Enter Tot Line 2 less 25), Carry to Pg117, line 27		151,053,637	236,786,566	—	—

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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 stockholders 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) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,457,281,533	1,354,290,003	—	—	—	—	2
						3
959,566,470	775,260,766	—	—	—	—	4
71,517,702	58,504,460	—	—	—	—	5
206,700,423	175,173,693	—	—	—	—	6
619,089	637,302	—	—	—	—	7
—	11,735,700	—	—	—	—	8
1,418,021	1,707,827	—	—	—	—	9
—	—	—	—	—	—	10
—	—	—	—	—	—	11
17,193,753	16,653,815	—	—	—	—	12
1,401,137	1,656,841	—	—	—	—	13
55,703,007	49,008,459	—	—	—	—	14
(19,743,037)	(6,209,687)	—	—	—	—	15
(4,022,039)	(5,490,249)	—	—	—	—	16
318,155,938	299,429,096	—	—	—	—	17
310,208,021	274,904,269	—	—	—	—	18
(169,438)	7,224,165	—	—	—	—	19
152,204	—	—	—	—	—	20
—	—	—	—	—	—	21
11	22	—	—	—	—	22
—	—	—	—	—	—	23
11,049,380	10,429,222	—	—	—	—	24
1,306,227,897	1,117,503,437	—	—	—	—	25
151,053,636	236,786,566	—	—	—	—	26

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Ended Quarterly Only No (e)	Months Ended Quarterly Only No 4th (f)
27	Net Utility Operating Income (Carried forward from page 114)		151,053,637	236,786,566	—	—
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing, & Contract Work (415)		3,017,961	1,574,103	—	—
32	(Less) Costs, Exp. Of Merchandising, Job & Contract Work(416)		3,009,999	1,312,730	—	—
33	Revenues from Nonutility Operations (417)		—	—	—	—
34	(Less) Expenses of Nonutility Operations (417.1)		—	—	—	—
35	Nonoperating Rental Income (418)		—	—	—	—
36	Equity in Earnings of Subsidiary Companies (418.1)	119	—	—	—	—
37	Interest and Dividend Income (419)		17,190,516	23,100,689	—	—
38	Allowance for Other Funds Used During Construction (419.1)		9,706,809	13,042,686	—	—
39	Miscellaneous Nonoperating Income (421)		43,056,334	44,207,594	—	—
40	Gain on Disposition of Property (421.1)		602,912	(161,480)	—	—
41	TOTAL Other Income (Enter Total of lines 31-40)		70,564,533	80,450,862	—	—
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		6,497	112,831	—	—
44	Miscellaneous Amortization (425)		844,446	844,446	—	—
45	Donations (426.1)		142,803	156,711	—	—
46	Life Insurance (426.2)		—	—	—	—
47	Penalties (426.3)		(121,570)	(17,694)	—	—
48	Exp for Certain Civic, Political & Related Activities (426.4)		6,935	84,191	—	—
49	Other Deductions (426.5)		12,061,757	19,889,886	—	—
50	TOTAL Other Income Deductions (Total of lines 43-49)		12,940,868	21,070,371	—	—
51	Taxes Applic. To Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	—	—	—	—
53	Income Taxes - Federal (409.2)	262-263	10,698,960	985,658	—	—
54	Income Taxes - Other (409.2)	262-263	2,908,072	309,438	—	—
55	Provision for Deferred Income Taxes (410.2)	234,272-277	31,746,724	31,169,234	—	—
56	(Less) Provision for Deferred Income Taxes-Cr (411.2)	234,272-277	33,809,000	21,015,339	—	—
57	Investment Tax Credit Adj. - Net (411.5)		—	—	—	—
58	(Less) Investment Tax Credits (420)		—	—	—	—
59	TOTAL Taxes on Other Income&Deduction(Total of lines 52-58)		11,544,756	11,448,991	—	—
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		46,078,909	47,931,500	—	—
61	Interest Charges					
62	Interest on Long-Term Debt (427)		101,771,649	74,249,561	—	—
63	Amort. of Debt Disc. & Expense (428)		1,861,420	1,914,543	—	—
64	Amortization of Loss on Reacquired Debt (428.1)		391,099	454,645	—	—
65	(Less) Amort. of Premium on Debt-Credit (429)		—	—	—	—
66	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)		—	—	—	—
67	Interest on Debt to Assoc. Companies (430)		249,996	142,416	—	—
68	Other Interest Expense (431)		19,169,358	21,866,834	—	—
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		13,940,110	12,852,414	—	—
70	Net Interest Charges (Total of lines 62-69)		109,503,412	85,775,585	—	—
71	Income Before Extraordinary Items (Total of Lines 27, 60, 70)		87,629,134	198,942,481	—	—
72	Extraordinary Items					
73	Extraordinary Income (434)		—	—	—	—
74	(Less) Extraordinary Deductions (435)		—	8,980,131	—	—
75	Net Extraordinary Items (Total of Line 73 less line 74)		—	(8,980,131)	—	—
76	Income Taxes-Federal and Other (409.3)	262-263	—	(2,280,980)	—	—
77	Extraordinary Items After Taxes (line 75 less line 76)		—	(6,699,151)	—	—
78	Net Income (Total of lines 71 & 77)		87,629,134	192,243,330	—	—

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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		610,280,237	469,564,949
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		—	—
10	Dividends to Parent		—	(51,000,000)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		—	(51,000,000)
16	Balance Transferred from Income (Account 433 less Account 418.1)		87,629,134	192,243,330
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	4.58% Cumulative Adjustment to Preferred Dividend Account		(528,042)	(528,042)
25	Adjustment to Preferred Dividend Account		(1)	—
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Account 437)		(528,043)	(528,042)
30	Dividends Declared-Common Stock (Account 438)			
31				
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Account 438)		—	—
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		—	—
38	Balance - End of Period (Total 1, 9, 15, 16, 22, 29, 36, 37)		697,381,328	610,280,237
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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)
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)		697,381,328	610,280,237
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		—	—
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)		—	—

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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)	87,629,134	192,243,330
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	219,786,914	199,683,744
5	Realized (Gain)/Loss on investment securities	(34,749,968)	(26,851,362)
6	Amortization of Regulatory Assets and Liabilities (A/C 407.3)	17,193,753	16,653,815
7	Nuclear Fuel (A/C 401)	14,834,498	17,286,412
8	Deferred Income Taxes (Net)	5,885,641	34,678,722
9	Investment Tax Credit Adjustment (Net)	(169,438)	7,224,165
10	Net (Increase) Decrease in Receivables	(23,128,428)	(30,431,765)
11	Net (Increase) Decrease in Inventory	(3,061,176)	(26,036,430)
12	Net (Increase) Decrease in Allowances Inventory	—	—
13	Net Increase (Decrease) in Payables and Accrued Expenses	24,194,913	(24,379)
14	Net (Increase) Decrease in Other Regulatory Assets	19,756,374	21,300,463
15	Net Increase (Decrease) in Other Regulatory Liabilities	(25,356,429)	(125,792,464)
16	(Less) Allowance for Other Funds Used During Construction	9,706,809	13,042,686
17	(Less) Undistributed Earnings from Subsidiary Companies	—	—
18	Other (provide details in footnote):	58,768,000	—
18.1	Amortization of Debt Premium, Discount, and Expense(A/C 181,189,225,226)	2,728,195	2,848,052
18.2	Amortization of Rights-of-Way (A/C 186, 253)	6,970,666	6,493,059
18.3	Change in Intercompany	(5,503,685)	198,255
18.4	Provisions for Uncollectible Accounts	4,550,851	4,184,425
18.5	Regulatory Disallowances	(730,972)	8,980,131
18.6	(Gains)/Losses on Disposition of Property	(152,229)	—
19	Net Change in Deferred Charges	(8,590,469)	(10,099,639)
20	Net Change in Deferred Credits	(9,494,932)	18,144,134
21	Net Change in Current Assets and Liabilities	(6,377,662)	(13,142,666)
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	335,276,742	284,497,316
23			
24	Cash Flows from Investment Activities:	—	—
25	Construction and Acquisition of Plant (including land):	—	—
26	Gross Additions to Utility Plant (less nuclear fuel)	(559,508,251)	(652,863,279)
27	Gross Additions to Nuclear Fuel	(18,977,198)	(16,978,794)
28	Gross Additions to Common Utility Plant	—	—
29	Gross Additions to Nonutility Plant	—	—
30	(Less) Allowance for Other Funds Used During Construction	9,706,809	13,042,686
31	Other (provide details in footnote):	—	—
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(588,192,258)	(682,884,759)
35			

STATEMENT OF CASH FLOWS

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)
36	Acquisition of Other Noncurrent Assets (d)	—	—
37	Proceeds from Disposal of Noncurrent Assets (d)	—	2,839,712
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	Other Investing Income	(117,635)	14,884,704
44	Purchase of Investment Securities (a)	(714,392,680)	(756,804,628)
45	Proceeds from Sales of Investment Securities (a)	693,277,832	707,338,252
46	Loans Made or Purchased	—	—
47	Collections on Loans	—	—
48			
49	Net (Increase) Decrease in Receivables	—	—
50	Net (Increase) Decrease in Inventory	—	—
51	Net (Increase) Decrease in Allowances Held for Speculation	—	—
52	Net Increase (Decrease) in Payables and Accrued Expenses	—	—
53	Other (provide details in footnote):	—	—
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	(609,424,741)	(714,626,719)
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	965,000,000	398,000,000
62	Preferred Stock	—	—
63	Common Stock	—	—
64	Other (provide details in footnote):	—	—
65	Equity Contribution from Parent	123,300,000	55,000,000
66	Net Increase in Short-Term Debt (c)	—	226,300,000
67	Other (provide details in footnote):	—	—
67.1	Transmission Interconnection and Security Deposit Arrangements	20,120,296	81,021,710
68	Net Increase in Affiliate Short-Term Debt	—	—
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,108,420,296	760,321,710
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	(554,000,000)	(198,000,000)
74	Preferred Stock	—	—
75	Common Stock	—	—
76	Other (provide details in footnote):	—	—
76.1	Debt Issuance Cost and Other	(6,644,509)	(4,663,709)
76.2	Refunds Paid Under Transmission Interconnection and Security Deposit	(90,778,630)	(74,161,310)
77			
78	Net Decrease in Short-Term Debt (c)	(185,000,000)	—
79		—	—
80	Dividends on Preferred Stock	(528,042)	(528,042)
81	Dividends on Common Stock	—	(51,000,000)
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	271,469,115	431,968,649
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	(2,678,884)	1,839,246
87			
88	Cash and Cash Equivalents at Beginning of Period	2,697,609	858,363
89			
90	Cash and Cash Equivalents at End of period	18,725	2,697,609

FOOTNOTE DATA

Page 120, Row 18, Column (b)

Other non-cash charge to income for 2025 of $58,768,000 relates to Pension settlement charge. See page 123.57.

Page 121, Row 4, Column (b)

	December 31, 2025	December 31, 2024
Depreciation Expense (A/C 403)	206,700,423	175,173,693
Depreciation Expense for Asset Retirement Costs (A/C 403.1)	619,089	637,302
Accretion Expense (A/C 411.10)	11,049,380	10,429,222
Amortization & Depletion of Utility Plant (A/C 404, 405)	—	11,735,700
Amortization of Utility Plant Acq. Adj. (A/C 406)	1,418,021	1,707,827
	$ 219,786,913	$ 199,683,744

Page 121, Row 90, Column (b)

	December 31, 2025	December 31, 2024
Cash (Account 131)	$ —	$ 2,678,779
Temporary cash investments (Account 136)	—	—
Working funds (Account 135)	18,725	18,830
	$ 18,725	$ 2,697,609
Supplemental cash flow disclosures:		
Interest paid, net of amounts capitalized	$ 91,915,138	$ 70,088,845
Income taxes paid (refunded), net	$ (13,335,737)	$ (4,057,849)
Supplemental noncash investing activities:		
(Increase) decrease in accrued plant additions	$ (14,922,945)	$ 25,954,975

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	10,652,747	—	—	(77,158,206)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(9,778,288)	—	—	3,629,653
3	Preceding Quarter/Year to Date Changes in Fair Value	(658,983)	—	—	(2,394,504)
4	Total (lines 2 and 3)	(10,437,271)	—	—	1,235,149
5	Balance of Account 219 at End of Preceding Quarter/Year	215,476	—	—	(75,923,057)
6	Balance of Account 219 at Beginning of Current Year	215,476	—	—	(75,923,057)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(586,984)	—	—	47,941,951
8	Current Quarter/Year to Date Changes in Fair Value	589,867	—	—	2,059,983
9	Total (lines 7 and 8)	2,883	—	—	50,001,934
10	Balance of Account 219 at End of Current Quarter/Year	218,359	—	—	(25,921,123)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	4/17/2026	End of 2025/Q4

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	—	—	(66,505,459)		
2	—	—	(6,148,635)		
3	—	—	(3,053,487)		
4	—	—	(9,202,122)	192,243,330	183,041,208
5	—	—	(75,707,581)		
6	—	—	(75,707,581)		
7	—	—	47,354,967		
8	—	—	2,649,850		
9	—	—	50,004,817	87,629,134	137,633,951
10	—	—	(25,702,764)		

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.

GLOSSARY

Definitions:

2024 Rate Change	PNM's request for a general increase in electric rates filed with the NMPRC on December 5, 2022 using a calendar year 2024 FTY
2025 Rate Request	PNM's request for a general increase in electric rates filed with the NMPRC on June 14, 2024 using a FTY beginning July 1, 2025
2026 Resource Application	PNM's October 25, 2023 application with the NMPRC for approval of resources to be available for the 2026 summer peak
ABCWUA	Albuquerque Bernalillo County Water Utility Authority
ABO	Accumulated Benefit Obligation
ACE Rule	Affordable Clean Energy Rule
AEP OnSite Partners	AEP OnSite Partners, LLC, a subsidiary of American Electric Power, Inc.
Afton	Afton Generating Station
AFUDC	Allowance for Funds Used During Construction
AMS	Advanced Meter System
AOCI	Accumulated Other Comprehensive Income
APBO	Accumulated Postretirement Benefit Obligation
APS	Arizona Public Service Company, the operator and a co-owner of PVNGS and Four Corners
ARO	Asset Retirement Obligation
ARP	Alternative Revenue Program
ASU	Accounting Standards Update
Avangrid	Avangrid, Inc., a New York corporation
Avangrid Merger	The merger of TXNM pursuant to the Merger Agreement, with TXNM surviving the Merger as a direct, wholly-owned subsidiary of Avangrid (Subsequently terminated December 31, 2023)
Avangrid Merger Agreement	The Agreement and Plan of Merger, dated October 20, 2020. (Subsequently terminated December 31, 2023)
BART	Best Available Retrofit Technology
Blackstone Infrastructure	Blackstone Infrastructure Partners L.P.
Board	Board of Directors of TXNM
BTU	British Thermal Unit
CAA	Clean Air Act
CAISO	California Independent System Operator
Carbon Pollution Standards	Carbon Pollution Standards established by the EPA on August 3, 2015
Casa Mesa Wind	Casa Mesa Wind Energy Center
CCN	Certificate of Convenience and Necessity
CCR	Coal Combustion Residuals
CCS	Carbon Capture Storage/ Sequestration
CIAC	Contributions in Aid of Construction
CO_2	Carbon Dioxide
CODM	Chief Operating Decision Maker
Community Solar Act	Senate Bill 84 effective June 18, 2021
Convertible Notes	TXNM's $550.0 million junior subordinated convertible notes due 2054; issued in private offerings on June 10, 2024 and June 21, 2024
COVID-19	Novel coronavirus global pandemic
CSA	Coal Supply Agreement

GLOSSARY

CWIP	Construction work in progress
DC Circuit	United States Court of Appeals for the District of Columbia Circuit
DCRF	Distribution cost recovery filing
DOE	United States Department of Energy
EDAM	Extended Day Ahead Market
EEI	Edison Electric Institute, an association representing all US investor-owned electric companies.
Effective Time	The time the Merger is consummated
EGU	Electric Generating Unit
EIM	Western Energy Imbalance Market developed and operated by CAISO
ELG	Effluent Limitation Guidelines
Energy Transition Charge	Rate rider established to collect non-bypassable customer charges for repayment of the ETBC I Securitized Bonds
EPA	United States Environmental Protection Agency
EPE	El Paso Electric Company
ERCOT	Electric Reliability Council of Texas
ESA	Energy Storage Agreement
ETA	The New Mexico Energy Transition Act
ETBC I	PNM Energy Transition Bond Company I, LLC, formed on August 25, 2023
ETBC I Securitized Bonds	On November 15, 2023, ETBC I issued $343.2 Million aggregate principal amount of its senior secured energy transition bonds, Series A in two tranches.
EUEA	The New Mexico Efficient Use of Energy Act
EV	Electric Vehicle
Exchange Act	Securities Exchange Act of 1934
Farmington	The City of Farmington, New Mexico
FASB	Financial Accounting Standards Board
FAST Act	SEC's modernization and simplification of Regulation S-K
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
FMB	First Mortgage Bond
Four Corners	Four Corners Power Plant
Four Corners Abandonment Application	PNM's January 8, 2021 application for approval for the abandonment of Four Corners and issuance of a securitized financing order
Four Corners CSA	Four Corners' coal supply contract with NTEC
Four Corners Purchase and Sale Agreement	PNM's pending sale of its 13% ownership interest in Four Corners to NTEC
FPPAC	Fuel and Purchased Power Adjustment Clause
FTY	Future Test Year
GAAP	Generally Accepted Accounting Principles in the United States of America
GHG	Greenhouse Gas Emissions
Grid Modernization Plan	PNM's NMPRC approved plan for grid modernization that includes investments of approximately $367 million for the first six years of a broader 11-year strategy
GWh	Gigawatt hours
IBEW	International Brotherhood of Electrical Workers
INDC	Intended Nationally Determined Contribution

GLOSSARY

IRA	Inflation Reduction Act
IRC	Internal Revenue Code
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ISFSI	Independent Spent Fuel Storage Installation
June 2025 Stock Purchase Agreement	TXNM's agreement for sale of 3,615,003 shares of TXNM common stock for a purchase price of $55.325 per share
kV	Kilovolt
KW	Kilowatt
KWh	Kilowatt Hour
La Joya Wind I	La Joya Wind Facility generating 166 MW of output that became operational in February 2021
La Joya Wind II	La Joya Wind Facility generating 140 MW of output that became operational in June 2021
La Luz	La Luz Generating Station
Leased Interest	Leased capacity in PVNGS Unit 1 and Unit 2
Lordsburg	Lordsburg Generating Station
Luna	Luna Energy Facility
May 2025 Stock Purchase Agreement	TXNM's agreement for sale of 8,000,000 shares of TXNM common stock for a purchase price of $50.00 per share
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Merger	The merger of TXNM pursuant to the Merger Agreement, with TXNM surviving as a direct, wholly-owned subsidiary of Parent (an affiliate of Blackstone Infrastructure Partners L.P.)
Merger Agreement	The Agreement and Plan of Merger, dated May 18, 2025, by and among TXNM, Parent, and Merger Sub
Merger Sub	Troy Merger Sub Inc., a New Mexico corporation, direct subsidiary of Parent and affiliate of Blackstone Infrastructure Partners L.P., which will merge with and into TXNM at the Effective Time of the Merger
Meta	Meta Platform, Inc., formerly known as Facebook Inc.
MMBTU	Million BTUs
Moody's	Moody's Investor Services, Inc.
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trusts for PVNGS
NEE	New Energy Economy
NERC	North American Electric Reliability Corporation
New Mexico Wind	New Mexico Wind Energy Center
NM 2015 Rate Case	Request for a General Increase in Electric Rates Filed by PNM on August 27, 2015
NM 2016 Rate Case	Request for a General Increase in Electric Rates Filed by PNM on December 7, 2016
NM Supreme Court	New Mexico Supreme Court
NMED	New Mexico Environment Department

GLOSSARY

NMMMD	The Mining and Minerals Division of the New Mexico Energy, Minerals and Natural Resources Department
NMPRC	New Mexico Public Regulation Commission
NMRD	NM Renewable Development, LLC, owned 50% each by PNMR Development and AEP OnSite Partners, LLC
NOx	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
NTEC	Navajo Transitional Energy Company, LLC, an entity owned by the Navajo Nation
OATT	Open Access Transmission Tariff
OBBBA	One Big Beautiful Bill Act of 2025
OCI	Other Comprehensive Income
OMB	Office of Management and Budget
OPEB	Other Post-Employment Benefits
OSM	United States Office of Surface Mining Reclamation and Enforcement
Parent	Troy ParentCo LLC, a Delaware limited liability company and an affiliate of Blackstone Infrastructure Partners L.P.
Paris Agreement	A legally binding international treaty on climate change adopted on December 12, 2015
Pattern Wind	Pattern New Mexico Wind, LLC, an affiliate of Western Spirit and Pattern Development
PBO	Projected Benefit Obligation
PCRBs	Pollution Control Revenue Bonds
PM	Particulate Matter
PNM	Public Service Company of New Mexico and Subsidiaries
PNM New Mexico Credit Facility	PNM's $40.0 million Unsecured Revolving Credit Facility
PNM 2021 Note Purchase Agreement	PNM's Agreement for the sale of PNM's 2021 SUNs
PNM 2021 SUNs	PNM's $160.0 million Senior Unsecured Notes issued on July 14, 2021
PNM 2021 Term Loan	PNM's $75.0 million 18-month Unsecured term loan that was repaid on August 5, 2022
PNM 2022 Delayed- Draw Term Loan	PNM's $225.0 million Unsecured term loan that matured February 5, 2024
PNM 2023 Note Purchase Agreement	PNM's agreement for sale of PNM's 2023 SUNs
PNM 2023 SUNs	PNM's $200.0 million aggregate principal amount of two series of Senior Unsecured Notes issued on April 28, 2023
PNM 2024 Term Loan	PNM's $200.0 million term loan that matured November 10, 2025
PNM 2025 Term Loan	PNM's $195.0 million term loan that matures July 21, 2026
PNM April 2025 Note Purchase Agreement	PNM's agreement for sale of PNM's April 2025 SUNs
PNM April 2025 SUNs	PNM's $300.0 million aggregate principal amount of two series of Senior Unsecured Notes issued on April 23, 2025

GLOSSARY

PNM July 2025 Note Purchase Agreement	PNM's agreement for sale of PNM's July 2025 SUNs
PNM July 2025 SUNs	PNM's $350.0 million aggregate principal amount of two series of Senior Unsecured Notes issued on July 31, 2025
PNM November 2025 Term Loan	PNM's $120.0 million term loan that matures on May 10, 2027
PNM Revolving Credit Facility	PNM's $400.0 million Unsecured Revolving Credit Facility
PNM September 2021 Note Purchase Agreement	PNM's agreement for the sale of PNM's September 2021 SUNs
PNM September 2021 SUNs	PNM's $150.0 million Senior Unsecured Notes issued on December 2, 2021
PNMR Development	PNMR Development and Management Company, an unregulated wholly-owned subsidiary of TXNM
PPA	Power Purchase Agreement
PSPS Plan	PNM's Public Safety Power Shutoff Plan filed with the NMPRC on May 1, 2024
PUCT	Public Utility Commission of Texas
PV	Photovoltaic
PVNGS	Palo Verde Nuclear Generating Station
PVNGS Leased Interest Abandonment Application	Application with the NMPRC requesting approval for the decertification and abandonment of 114MW of leased PVNGS capacity
RCT	Reasonable Cost Threshold
RD	Recommended Decision
REA	New Mexico's Renewable Energy Act of 2004
RECs	Renewable Energy Certificates
Red Mesa Wind	Red Mesa Wind Energy Center
REP	Retail Electricity Provider
RFP	Request For Proposal
Rio Bravo	Rio Bravo Generating Station, formerly known as Delta
ROE	Return on Equity
RPS	Renewable Energy Portfolio Standard
S&P	Standard and Poor's Ratings Services
SCE	Southern California Edison Company
SCPPA	Southern California Public Power Authority
SEC	United States Securities and Exchange Commission
Securities Act	The Securities Act of 1933, as amended
Securitized Bonds	Energy transition bonds
SIP	State Implementation Plan
SJCC	San Juan Coal Company
SJGS	San Juan Generating Station
SJGS Abandonment Application	PNM's July 1, 2019 consolidated application seeking NMPRC approval to retire PNM's share of SJGS in 2022, for related replacement generating resources, and for the issuance of Securitized Bonds under the ETA
SJGS CSA	San Juan Generating Station Coal Supply Agreement
SO_2	Sulfur Dioxide
SOFR	Secured Overnight Financing Rate
SRP	Salt River Project
SUNs	Senior Unsecured Notes

GLOSSARY

Tax Act	Federal tax reform legislation enacted on December 22, 2017, commonly referred to as the Tax Cuts and Jobs Act
TCEQ	Texas Commission on Environmental Quality
TCOS	Transmission Cost of Service
TECA	Texas Electric Choice Act
TEP	Transportation Electrification Program
TNMP	Texas-New Mexico Power Company and Subsidiaries
TNMP 2018 Rate Case	TNMP's General Rate Case Application filed on May 30, 2018
TNMP 2023 Bonds	TNMP's FMBs to be issued under the TNMP 2023 Bond Purchase Agreement
TNMP 2023 Bond Purchase Agreement	TNMP's agreement for the sale of an aggregate $185.0 million of two series of TNMP's 2023 Bonds
TNMP 2024 Bonds	TNMP's FMBs to be issued under the TNMP 2024 Bond Purchase Agreement
TNMP 2024 Bond Purchase Agreement	TNMP's agreement for the sale of an aggregate $285.0 million of four series of TNMP's 2024 Bonds
TNMP Base Rate Review	TNMP's general rate review application filed with the PUCT in November 2025
TNMP February 2025 Bonds	TNMP's FMBs to be issued under the TNMP February 2025 Bond Purchase Agreement
TNMP February 2025 Bond Purchase Agreement	TNMP's agreement for the sale of an aggregate $140.0 million of TNMP's February 2025 Bonds
TNMP FMBs	TNMP's $1,505.0 million in outstanding FMBs
TNMP July 2025 Bond Purchase Agreement	TNMP's agreement for the sale of an aggregate $1,084.3 million of six series of TNMP's July 2025 FMBs
TNMP July 2025 FMBs	TNMP's FMBs to be issued under the TNMP July 2025 Bond Purchase Agreement
TNMP Merger Backstop Term Loan	TNMP's $1,505.0 million, 364-day delayed-draw term loan that terminated on July 22, 2025
TNMP November 2025 Bond Purchase	TNMP's agreement for the sale of an aggregate $70.0 million of TNMP's November 2025 FMBs
TNMP November 2025 FMBs	TNMP's FMBs to be issued under the TNMP November 2025 Bond Purchase Agreement
TNMP Revolving Credit Facility	TNMP's $200.0 million Secured Revolving Credit Facility
TNP	TNP Enterprises, Inc. and Subsidiaries
TOD	Time of Day
Tucson	Tucson Electric Power Company
TXNM	TXNM Energy, Inc. formerly known as PNM Resources, Inc. ("PNMR")
TXNM 2021 Delayed-Draw Term Loan	TXNM's $1.0 billion delayed-draw term loan that matured on May 18, 2025
TXNM 2022 ATM Program	TXNM's distribution agreement pursuant to which the Company issued and sold an aggregate sales price of $200.0 million of TXNM common stock, no par value, through the sales agents
TXNM 2023 Term Loan	TXNM $500.0 million term loan that matures on June 30, 2026
TXNM 2024 ATM Program	TXNM's distribution agreement pursuant to which the Company issued and sold an aggregate sales price of $300.0 million of TXNM common stock, no par value, through the sales agents

GLOSSARY

TXNM 2025 ATM Program	TXNM's distribution agreement pursuant to which the Company issued and sold an aggregate sales price of $200.0 million of TXNM common stock, no par value, through the sales agents
TXNM 2025 Junior Subs	TXNM's $350.0 million 7.00% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due 2056
TXNM Merger Backstop Revolving Facility	TXNM's $910.0 million 364-day revolving credit facility
TXNM Revolving Credit Facility	TXNM's $300.0 million Unsecured Revolving Credit Facility
U.S.	The Unites States of America
US Supreme Court	United States Supreme Court
Valencia	Valencia Energy Facility
VIE	Variable Interest Entity
WACC	Weighted Average Cost of Capital
Western Spirit Line	An approximately 150-mile 345-kV transmission line that PNM purchased in December 2021
Westmoreland	Westmoreland Coal Company
WFB LOC Facility	Letter of credit arrangements with Wells Fargo Bank, N.A., entered into in August 2020
WMP	PNM's Wildfire Mitigation Plan filed with the NMPRC on May 1, 2024
WRAP	Western Resource Adequacy Program
WSJ	Westmoreland San Juan, LLC, an indirect wholly-owned subsidiary of Westmoreland
WSJ LLC	Westmoreland San Juan, LLC, a subsidiary of Westmoreland Mining Holdings, LLC, and current owner of SJCC
WSPP	Western Systems Power Pool

Reconciliation of FERC and GAAP Differences

The financial statements presented herein are prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than GAAP. The primary differences between the FERC accounting requirements and GAAP are (1) deferred tax assets (Account 190) are shown on the asset side of the balance sheet for FERC purposes, but are netted against deferred tax liabilities under GAAP; (2) the current portion of long-term debt is shown in current liabilities under GAAP, but not for FERC purposes; (3) the tax effect of the items included in the Statement of Accumulated Comprehensive Income, Comprehensive Income and Hedging Activities is not required to be disclosed separately for FERC, but is required under GAAP; (4) cost of removal for GAAP is reclassified and recorded as a regulatory liability, whereas under FERC it is in Account 108 (Accumulated Provision for Depreciation of Electric Utility Plant); (5) certain components of the costs of pension and OPEB plans are recorded as regulatory assets for GAAP, but capitalized in other accounts (primarily, Account 107, Construction Work in Progress) for FERC and other components of the costs of pension and OPEB plans are charged to Other (deductions) for GAAP, but charged to Account 926 (Employee Pensions and Benefits) for FERC; (6) Valencia is required to be consolidated under GAAP, but is treated as a PPA for FERC; (7) accumulated provision for injuries and damages is recorded net of expected insurance proceeds for FERC, but not for GAAP; (8) regulatory disallowances and restructuring costs are classified as extraordinary items for FERC, but not for GAAP; (9) debt issuance costs are classified as a reduction of the related long-term debt under GAAP, but not for FERC purposes; (10) Leases are recorded differently for GAAP and FERC (see additional discussion below); (11) gains and losses on the disposition of investments are recorded net in Account 421 for GAAP, while for FERC, losses are recorded to Account 426.5; (12) implementation costs for cloud computing service arrangements are treated as deferred costs for GAAP and are capitalized for FERC. Amortization of these costs are included with depreciation & amortization for FERC, but not for GAAP; (13) costs associated with the pending Blackstone Infrastructure Merger are reported as utility operating expenses for GAAP and as other deductions (426.5) for FERC; (14) ETBC I is required to be consolidated under GAAP but is accounted for using the equity method for FERC (15) certain classifications are treated differently for FERC purposes than under GAAP.

<u>Item 3 Utility Plant adjustments</u>

Four Corners Investment Impairment (NMPRC Case No. 16-00276-UT & NMPRC Case No. 22-00270-UT)

In the first quarter of 2018, PNM recognized a loss to reflect that PNM will not earn an equity return on $148.1 million of investments at Four Corners. Additionally, in the last quarter of 2023, the Final Order in NMPRC Case No. 22-00270-UT established a total impairment of $81 million. Amounts are being amortized ratably over the useful life of the underlying investments.

	December 31, 2024	2025 Amortization	December 31, 2025
Four Corners	$ (79,780,946)	$ 1,212,921	$ (78,568,025)
Account 116 Balance	$ (79,780,946)	$ 1,212,921	$ (78,568,025)

<u>Leases</u>

Accounting and Financial Reporting for Leases Accounting Standards Update (ASU) No. 2016-02 – FERC Docket No. AI19-1-000

PNM adopted accounting guidance (ASU) No. 2016-02, Leases (Topic 842) on January 1, 2019. Under FASB's new guidance, lessees are required to recognize on the balance sheet assets and liabilities for the rights and obligations created by lease arrangements for operating leases with terms of more than 12 months. The changes in accounting will have no impact on existing ratemaking treatment at PNM.

Additional disclosure information specified by FERC is provided below.

Utility Plant excluding leases	$	7,636,669,119
Operating leases		107,986,060
Financing leases*		17,691,389
Total Utility Plant	$	7,762,346,568
Obligations under operating leases	$	96,246,143
Obligations under financing leases		11,740,361
Total non-current lease obligations	$	107,986,504
Obligations under operating leases	$	8,912,966
Obligations under financing leases		5,764,612
Total current lease obligations	$	14,677,578

* Under GAAP, financing lease assets are depreciated, and interest expense is determined using the effective interest method resulting in higher interest expense at the beginning of the lease term, declining as the lease liability is reduced. Under FERC, interest expense on lease obligations is not recognized. Rather, the regulations provide that the depreciation recorded for the financing lease asset and the related obligation are reduced by equal and offsetting amounts over the lease term.

Refer to Footnote 8 on page 123.39 for additional information regarding leases.

A reconciliation of FERC Form 1 earnings to GAAP for the year ended December 31, 2025 is as follows:

		Earnings (in thousands)
Form 1 Earnings	$	87,629
Impacts of converting leases from FERC to GAAP		(24)
GAAP Earnings Attributable to PNM	$	87,605

The following Notes to Condensed Consolidated Financial Statements (see pages 123.10 - 123.105) represent those included in PNM’s Annual Report on Form 10-K, which are a component part of the financial statements prepared in accordance with GAAP and SEC reporting requirements. These notes are not significantly different than those prepared in support of the other comprehensive basis of accounting discussed above. The primary differences in disclosure relate directly to those differences mentioned above. The following Notes to Condensed Consolidated Financial Statements include disclosures for TXNM, PNM, and TNMP. Information solely applicable to TXNM or TNMP should be disregarded.

(1) Summary of the Business and Significant Accounting Policies

Nature of Business

TXNM is an investor-owned holding company with two regulated utilities providing electricity and electric services in New Mexico and Texas. TXNM's primary subsidiaries are PNM and TNMP. PNM is a public utility with regulated operations primarily engaged in the generation, transmission, and distribution of electricity. In 2023, ETBC I, a special purpose entity that is wholly-owned by PNM, was formed for the limited purpose of purchasing, owning, and administering energy transition property, issuing Securitized Bonds, and performing related activities. See Note 7. TNMP is a wholly-owned subsidiary of TNP, which is a holding company that is wholly-owned by TXNM. TNMP provides regulated transmission and distribution services in Texas. TXNM's common stock trades on the New York Stock Exchange under the symbol TXNM.

On May 18, 2025, TXNM, Parent, and Merger Sub, entered into the Merger Agreement, pursuant to which Merger Sub will merge with and into TXNM, with TXNM surviving the Merger as a direct, wholly-owned subsidiary of Parent. Parent and Merger Sub are affiliates of Blackstone Infrastructure. See Note 22.

Financial Statement Preparation and Presentation

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, 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 ultimately differ from those estimated.

On August 2, 2024, PNM Resources, Inc. ("PNMR") amended its Articles of Incorporation to change its name to TXNM Energy, Inc. ("TXNM") and increased the number of authorized shares of the Company's common stock from 120,000,000 to 200,000,000. The Notes to Consolidated Financial Statements include disclosures for TXNM, PNM, and TNMP. This report uses the term "Company" when discussing matters of common applicability to TXNM, PNM, and TNMP. Discussions regarding only TXNM, PNM, or TNMP are so indicated. Certain amounts in the 2024 and 2023 Consolidated Financial Statements and Notes thereto have been reclassified to conform to the 2025 financial statement presentation.

GAAP defines subsequent events as events or transactions that occur after the balance sheet date but before financial statements are issued or are available to be issued. Based on their nature, magnitude, and timing, certain subsequent events may be required to be reflected at the balance sheet date and/or required to be disclosed in the financial statements. The Company has evaluated subsequent events accordingly.

Principles of Consolidation

The Consolidated Financial Statements of each of TXNM, PNM, and TNMP include their accounts and those of subsidiaries in which that entity owns a majority voting interest. PNM also consolidates Valencia and ETBC I (Note 10). PNM owns undivided interests in jointly-owned power plants and records its pro-rata share of the assets, liabilities, and expenses for those plants. The agreements for the jointly-owned plants provide that if an owner were to default on its payment obligations, the non-defaulting owners would be responsible for their proportionate share of the obligations of the defaulting owner. In exchange, the non-defaulting owners would be entitled to their proportionate share of the generating capacity of the defaulting owner. There have been no such payment defaults under any of the agreements for the jointly-owned plants.

PNMR Services Company expenses, which represent costs that are primarily driven by corporate level activities, are charged to the business segments. These services are billed at cost and are reflected as general and administrative expenses in the business segments. Other significant intercompany transactions between TXNM, PNM, and TNMP include intercompany loans, interest and income tax sharing payments, as well as equity transactions, and interconnection billings. All intercompany transactions and balances have been eliminated. See Note 20.

Accounting for the Effects of Certain Types of Regulation

The Company maintains its accounting records in accordance with the uniform system of accounts prescribed by FERC and adopted by the NMPRC and PUCT.

Certain of the Company's operations are regulated by the NMPRC, PUCT, and FERC and the provisions of GAAP for rate-regulated enterprises are applied to the regulated operations. Regulators may assign costs to accounting periods that differ from accounting methods applied by non-regulated utilities. When it is probable that regulators will permit recovery of costs through future rates, costs are deferred as regulatory assets that otherwise would be expensed. Likewise, regulatory liabilities are recognized when it is probable that regulators will require refunds through future rates or when revenue is collected for expenditures that have not yet been incurred. GAAP also provides for the recognition of revenue and regulatory assets and liabilities associated with "alternative revenue programs" authorized by regulators. Such programs allow the utility to adjust future rates in response to past activities or completed events, if certain criteria are met. Regulatory assets and liabilities are amortized into earnings over the authorized recovery period. Accordingly, the Company has deferred certain costs and recorded certain liabilities pursuant to the rate actions of the NMPRC, PUCT, and FERC. Information on regulatory assets and regulatory liabilities is contained in Note 13.

In some circumstances, regulators allow a requested increase in rates to be implemented, subject to refund, before the regulatory process has been completed and a decision rendered by the regulator. When this occurs, the Company assesses the possible outcomes of the rate proceeding. The Company records a provision for refund to the extent the amounts being collected, subject to refund, exceed the amount the Company determines is probable of ultimately being allowed by the regulator.

Cash and Restricted Cash

Investments in highly liquid investments with original maturities of three months or less at the date of purchase are considered cash and cash equivalents. Cash deposits received and held for a period of time that are restricted to a specific purpose, under the terms of their effective agreements, are considered restricted cash. PNM and TXNM have restricted cash balances related to the ETBC I Securitized Bonds. Restricted cash amounts are included in Other current assets and Other deferred charges on the Consolidated Balance Sheets as of December 31, 2025 and 2024. See Note 10. At December 31, 2025 and 2024 there was no restricted cash for TNMP.

Utility Plant

Utility plant is stated at original cost and includes capitalized payroll-related costs such as taxes, pension, other fringe benefits, administrative costs, and AFUDC, where authorized by rate regulation, or capitalized interest.

Repairs, including major maintenance activities, and minor replacements of property are expensed when incurred, except as required by regulators for ratemaking purposes. Major replacements are charged to utility plant. Gains, losses, and costs to remove resulting from retirements or other dispositions of regulated property in the normal course of business are credited or charged to accumulated depreciation.

PNM and TNMP may receive reimbursements, referred to as CIAC, from customers to pay for all or part of certain construction projects to the extent the project does not benefit regulated customers in general. PNM and TNMP account for these reimbursements as offsets to utility plant additions based on the requirements of the NMPRC, FERC, and PUCT. Due to the PUCT's regulatory treatment of CIAC reimbursements, TNMP also receives a financing component that is recognized as Other income on the Consolidated Statements of Earnings. Under the NMPRC regulatory treatment, PNM typically does not receive a financing component.

Depreciation and Amortization

PNM's provision for depreciation of utility plant is based upon straight-line rates approved by the NMPRC and FERC. Amortization of nuclear fuel is based on units-of-production. Amortization of software is straight-line. TNMP's provision for depreciation and of utility plant is based upon straight-line rates approved by the PUCT. Amortization of software is straight-line. Depreciation and amortization of non-utility property, including right-of-use assets for finance leases as discussed in Note 8, is computed based on the straight-line method. The provision for depreciation of certain equipment is allocated between operating expenses and construction projects based on the use of the equipment. Average straight-line rates used were as follows:

	Year ended December 31,		
	2025	2024	2023
PNM			
Electric plant	2.88 %	2.87 %	2.67 %
Common and general plant	13.43	14.06	7.64
TNMP	3.75	3.74	3.77

Depreciation expense on electric, common, intangible, and general plant is as follows:

	Year ended December 31,		
	2025	2024	2023
		(In thousands)	
PNM	$ 207,341	$ 188,035	$ 158,956
TNMP	142,959	124,976	110,675

Allowance for Funds Used During Construction

As provided by the FERC uniform systems of accounts, AFUDC is charged to regulated utility plant for construction projects. This allowance is designed to enable a utility to capitalize financing costs during periods of construction of property subject to rate regulation. It represents the cost of borrowed funds (allowance for borrowed funds used during construction or “debt AFUDC”) and a return on other funds (allowance for equity funds used during construction or “equity AFUDC”). The debt AFUDC is recorded in interest charges and the equity AFUDC is recorded in other income on the Consolidated Statements of Earnings.

For the years ended December 31, 2025, 2024, and 2023, PNM recorded $13.9 million, $12.9 million, and $9.5 million of debt AFUDC at annual rates of 3.66%, 3.19%, and 2.99% and $9.7 million, $13.0 million, and $9.8 million of equity AFUDC at annual rates of 2.58%, 3.30%, and 3.24%. For the years ended December 31, 2025, 2024, and 2023, TNMP recorded $8.0 million, $8.0 million, and $5.7 million of debt AFUDC at rates of 3.01%, 4.14%, and 3.49%, and $8.9 million,$4.8 million, and $5.1 million of equity AFUDC at rates of 3.33%, 2.48%, and 3.17%.

Materials, Supplies, and Fuel Stock

Materials and supplies relate to transmission, distribution, and generating assets. Materials and supplies are charged to inventory when purchased and are expensed or capitalized as appropriate when issued. Materials and supplies are valued using an average costing method. Inventories consisted of the following at December 31:

	TXNM		PNM		TNMP	
	2025	2024	2025	2024	2025	2024
			(In thousands)			
Fuel Oil	$ 1,090	$ 1,095	$ 1,090	$ 1,095	$ —	$ —
Materials and supplies	180,226	165,766	144,573	141,415	35,653	24,351
	$ 181,316	$ 166,861	$ 145,663	$ 142,510	$ 35,653	$ 24,351

Investments

PNM holds investment securities in the NDT for the purpose of funding its share of the decommissioning costs of PVNGS, a trust for PNM’s share of decommissioning costs at SJGS, and trusts for PNM’s share of final reclamation costs related to the coal mines that served SJGS and continue to serve Four Corners (Note 16). Investments (both equity and available-for-sale debt securities) are measured at fair value on a quarterly basis with changes in fair value for equity securities recognized in earnings for that period. Since third party investment managers have sole discretion over the purchase and sale of the securities (under general guidelines and targets provided by management), PNM records an impairment, as a realized loss, for any available-for-sale debt security that has a fair value which is less than cost at the end of each quarter. For the years ended December 31, 2025, 2024 and 2023, PNM recorded impairment losses on the available-for-sale debt securities of $0.0 million, $17.8 million and $(19.1) million. No gains or losses are deferred as regulatory assets or liabilities. See Notes 3 and 9. All investments are held in PNM's name and are in the custody of major financial institutions. The specific identification method is used to determine the cost of securities disposed of, with realized gains and losses reflected in other income and deductions.

As discussed above, PNM immediately records an impairment loss for any available-for-sale debt security that has a fair value that is less than its carrying value. As a result, the Company has no available-for-sale debt securities for which carrying value exceeds fair value and there are no impairments considered to be "other than temporary" that are included in AOCI and not recognized in earnings. All gains and losses resulting from sales and changes in the fair value of equity securities are recognized immediately in earnings.

Equity Method Investment (Previously held)

TXNM accounted for its investment in NMRD using the equity method of accounting because TXNM's ownership interest resulted in significant influence, but not control, over NMRD and its operations. TXNM recorded as income its percentage share of earnings or loss of NMRD and carried its investment at cost, adjusted for its share of undistributed earnings or losses, until its investment was sold on February 27, 2024. See Note 21.

Goodwill

The Company does not amortize goodwill. Goodwill is evaluated for impairment annually, or more frequently if events and circumstances indicate that the goodwill might be impaired. See Note 19.

Asset Impairment

Tangible long-lived assets and right-of-use assets associated with leases are evaluated in relation to the estimated future undiscounted cash flows to assess recoverability when events and circumstances indicate that the assets might be impaired.

Revenue Recognition

See Note 4 for a discussion of electric operating revenues.

Accounts Receivable and Allowance for Credit Losses

See Note 4 for a discussion of accounts receivable and the allowance for credit losses.

Amortization of Debt Acquisition Costs

Discount, premium, and expense related to the issuance of long-term debt are amortized over the lives of the respective issues. Gains and losses incurred upon the early retirement of long-term debt are recognized in other income or other deductions, except for amounts recoverable through NMPRC, FERC, or PUCT regulation, which are recorded as regulatory assets or liabilities and amortized over the lives of the respective issues. Unamortized premium, discount, and expense related to long-term debt are reflected as part of the related liability on the Consolidated Balance Sheets.

Derivatives

The Company records derivative instruments, including energy contracts, on the balance sheet as either an asset or liability measured at their fair value. Changes in the derivatives' fair value are recognized in earnings unless specific hedge accounting criteria are met. PNM also records certain commodity derivative transactions recoverable through NMPRC regulation as regulatory assets or liabilities. See Note 9.

The Company treats all forward commodity purchases and sales contracts subject to unplanned netting or "book-out" by the transmission provider as derivative instruments subject to mark-to-market accounting. GAAP provides guidance on whether realized gains and losses on derivative contracts not held for trading purposes should be reported on a net or gross basis and concludes such classification is a matter of judgment that depends on the relevant facts and circumstances. See Note 4.

Decommissioning and Reclamation Costs

PNM is only required to recognize and measure decommissioning liabilities for tangible long-lived assets for which a legal obligation exists. Nuclear decommissioning costs and related accruals are based on periodic site-specific estimates of the costs for removing all radioactive and other structures at PVNGS and are dependent upon numerous assumptions, including estimates of future decommissioning costs at current price levels, inflation rates, and discount rates. PNM's accruals for PVNGS Units 1, 2, and 3, including portions previously held under leases, have been made based on such estimates, the guidelines of the NRC, and the PVNGS license periods. PNM records its share of the SJGS decommissioning obligation as an ARO on its Consolidated Balance Sheets. Studies on the decommissioning costs of SJGS are performed periodically and revisions to the ARO liability are recorded. See Note 16.

In connection with both the SJGS and Four Corners coal supply agreements, the owners are required to reimburse the mining companies for the cost of contemporaneous reclamation, as well as the costs for final reclamation of the coal mines. The reclamation costs are based on periodic site-specific studies that estimate the costs to be incurred in the future and are dependent upon numerous assumptions, including estimates of future reclamation costs at current price levels, inflation rates, and discount rates. PNM considers the contemporaneous reclamation costs part of the cost of its delivered coal costs. See Note 16 for a discussion of reclamation costs.

Environmental Costs

The normal operations of the Company involve activities and substances that expose the Company to potential liabilities under laws and regulations protecting the environment. Liabilities under these laws and regulations can be material and may be imposed without regard to fault, or may be imposed for past acts, even though the past acts may have been lawful at the time they occurred.

The Company records its environmental liabilities when site assessments or remedial actions are probable, and a range of reasonably likely cleanup costs can be estimated. The Company reviews its sites and measures the liability by assessing a range of reasonably likely costs for each identified site using currently available information and the probable level of involvement and financial condition of other potentially responsible parties. These estimates are based on assumptions regarding the costs for site investigations, remediation, operations and maintenance, monitoring, and site closure. The ultimate cost to clean up the Company's identified sites varies from its recorded liability due to numerous uncertainties inherent in the estimation process. See Note 16.

Pension and Other Postretirement Benefits

See Note 11 for a discussion of pension and postretirement benefits expense, including a discussion of the actuarial assumptions.

Stock-Based Compensation

See Note 12 for a discussion of stock-based compensation expense.

Income Taxes

Income taxes are recognized using the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying value of existing assets and liabilities and their respective tax basis. All deferred taxes are reflected as non-current on the Consolidated Balance Sheets. Current NMPRC, FERC, and PUCT approved rates include the tax effects of the majority of these differences. Rate-regulated enterprises are required to record deferred income taxes for temporary differences accorded flow-through treatment at the direction of a regulatory commission. The resulting deferred tax assets and liabilities are recorded based on the expected cash flow to be reflected in future rates. Because the NMPRC, FERC, and the PUCT have consistently permitted the recovery of tax effects previously flowed-through earnings, the Company has established regulatory assets and liabilities offsetting such deferred tax assets and liabilities. The Company recognizes only the impact of tax positions that, based on their merits, are more likely than not to be sustained upon an IRS audit. The Company defers investment tax credits and amortizes them over the estimated useful lives of the assets. See Note 18 for additional information, including a discussion of the impact of the Tax Act.

The Company makes an estimate of its anticipated effective tax rate for the year as of the end of each quarterly period within its fiscal year. In interim periods, income tax expense is calculated by applying the anticipated annual effective tax rate to year-to-date earnings before taxes. Certain unusual or infrequently occurring items, as well as adjustments due to enactment of new tax laws, have been excluded from the estimated annual effective tax rate calculation.

Lease Commitments

See Note 8 for a discussion of lease commitments.

New Accounting Pronouncements

Information concerning recently issued accounting pronouncements that have not yet been adopted by the Company is presented below. The Company does not expect difficulty in adopting these standards by their required effective dates.

Accounting Standards Update 2024-03 - Income Statement (Subtopic 220-40): Reporting Comprehensive Income - Expense Disaggregation Disclosures

In November 2024, the FASB issued ASU 2024-03 that will require disclosure, in the notes to the financial statements, of specified information about certain costs and expenses at each interim and annual period. Disclosures should include amounts for purchases of inventory, employee compensation, depreciation and, intangible asset amortization; certain amounts that are already required to be disclosed under GAAP in the same disclosure as other disaggregation requirements; qualitative descriptions of the amounts remaining in relevant expense categories that are not disaggregated; and the total amount of selling expenses including the entity’s definition of selling expenses. In January 2025, ASU 2025-01 was issued to clarify that the amendments of ASU 2024-03 are effective for public business entities for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027. The Company expects to adopt the disclosure requirements of ASU 2024-03 with its Annual Report on Form 10-K for the year ended December 31, 2027.

Accounting Standards Update 2025-05 – Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses for Accounts Receivable and Contract Assets

In July 2025, the FASB issued ASU 2025-05 that introduces a practical expedient for all entities and an accounting policy election for entities other than public business entities, related to applying Subtopic 326-20 to current accounts receivable and current contract assets arising from transactions accounted for under Topic 606. In developing a reasonable and supportable forecast as a part of estimating expected credit losses, all entities may elect a practical expedient that assumes that current conditions as of the balance sheet date do not change for the remaining life of the asset. Entities other than public business entities that elect the practical expedient are permitted to make an accounting policy election to consider collection activity after the balance sheet date when estimating expected credit losses. An entity that elects the practical expedient and the accounting policy election, if applicable, should apply the amendments in this update prospectively. The amendments in this update are effective for all entities for annual reporting periods beginning after December 15, 2025, and interim reporting periods within those annual reporting periods. Early adoption is permitted. The Company has not yet determined whether it will elect the practical expedient for estimating credit losses, however, it does not expect that this will have a material impact on its current allowance for expected credit losses.

Accounting Standards Update 2025-06 – Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Targeted Improvements to the Accounting for Internal-Use Software

In September 2025, the FASB issued ASU 2025-06 that updates the internal-use software guidance in subtopic 350-40 including the removal of all references to prescriptive and sequential developmental stages referred to as “project stages” throughout the subtopic. The new guidance requires an entity to start capitalizing software costs when management has authorized and committed to funding the project and it is probable that the project will be completed and used to perform the function it was intended for (referred to as the “probable-to-complete recognition threshold”). During the evaluation of the probable-to-complete recognition threshold, the entity is required to consider whether there is significant uncertainty associated with the development activities of the software. The amendments in this update are effective for all entities for annual reporting periods beginning after December 15, 2027, and interim reporting periods within those annual reporting periods. Early adoption is permitted as of the beginning of an annual reporting period. The amendments in this update permit an entity to apply the new guidance using a prospective transition approach, a modified transition approach (based on the status of a project and whether software costs were capitalized before the date of adoption), or a full retrospective transition approach. The Company has not yet determined which approach to adopt nor the impact that the new guidance will have on the accounting for its internal-use software projects.

(2) Segment Information

TXNM has three reportable segments including PNM, TNMP, and Corporate and other. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. The measure of profitability used by the CODM is Segment earnings (loss) attributable to TXNM, as presented below. The CODM uses this measure of profitability to allocate resources for each segment predominantly in the annual budget and forecasting process. The CODM considers budget to actual variances on a regular basis when making decisions about allocating capital and operational expense funding to the segments. TXNM’s CODM is its President and CEO who is also the CEO of the PNM and TNMP segments.

PNM

PNM includes the retail electric utility operations of PNM that are subject to traditional rate regulation by the NMPRC. PNM provides integrated electricity services that include the generation, transmission, and distribution of electricity for retail electric customers in New Mexico. PNM also includes the generation and sale of electricity into the wholesale market, which includes the asset optimization of PNM’s jurisdictional capacity as well as providing transmission services to third parties. FERC has jurisdiction over wholesale power and transmission rates. PNM includes the results of ETBC I upon its formation in 2023.

TNMP

TNMP is an electric utility providing services in Texas under the TECA. TNMP’s operations are subject to traditional rate regulation by the PUCT. TNMP provides transmission and distribution services at regulated rates to various REPs that, in turn, provide retail electric service to consumers within TNMP’s service area. TNMP also provides transmission services at regulated rates to other utilities that interconnect with TNMP’s facilities.

Corporate and Other

The Corporate and Other segment includes TXNM holding company activities, primarily related to corporate level debt and PNMR Services Company. The activities of PNMR Development and the equity method investment in NMRD are also included in Corporate and Other until the close of the sale of NMRD on February 27, 2024 (Note 21). Eliminations of intercompany transactions are reflected in the Corporate and Other segment.

The following tables present summarized financial information for TXNM by segment. PNM and TNMP each operate in only one segment. Therefore, tabular segment information is not presented for PNM and TNMP.

2025	**PNM**	**TNMP**	**Corporate and Other**	**TXNM Consolidated**
		(In thousands)		
Electric operating revenues	$ 1,484,290	$ 681,316	$ —	$ 2,165,606
Cost of energy				
Fuel burn	131,395	—	—	131,395
Purchases for resale	393,154	—	—	393,154
Transmission by others	24,607	166,849	—	191,456
Significant segment expenses				
Administrative and general - direct	76,659	252	163,673	240,584
Administrative and general - corporate allocation	133,410	53,852	(187,262)	—
Customer related expenses	30,783	3,086	—	33,869
Energy production costs	98,371	—	—	98,371
Regulatory disallowances	(731)	—	—	(731)
Depreciation and amortization	244,205	143,942	37,494	425,641
Transmission and distribution costs	63,349	37,445	—	100,794
Taxes other than income taxes	56,485	47,174	6,235	109,894
Total operating expenses	1,251,687	452,600	20,140	1,724,427
Net other income and (deductions)	(2,026)	14,615	(2,233)	10,356
Interest charges	(129,478)	(86,956)	(55,088)	(271,522)
Income taxes (benefit)	(4,442)	32,085	(17,456)	10,187
Valencia non-controlling interest	(17,936)	—	—	(17,936)
Subsidiary preferred stock dividends	(528)	—	—	(528)
Segment earnings (loss) attributable to TXNM	$ 87,077	$ 124,290	$ (60,005)	$ 151,362
At December 31, 2025:				
Total Assets	$ 7,688,132	$ 4,187,718	$ 183,435	$ 12,059,285
Goodwill	$ 51,632	$ 226,665	$ —	$ 278,297

2024	PNM	TNMP	Corporate and Other	TXNM Consolidated
		(In thousands)		
Electric operating revenues	$ 1,379,088	$ 592,111	$ —	$ 1,971,199
Cost of energy				
Fuel burn	130,380	—	—	130,380
Purchases for resale	286,399	—	—	286,399
Transmission by others	18,139	149,066	—	167,205
Significant segment expenses				
Administrative and general - direct	63,105	(1,452)	151,089	212,742
Administrative and general - corporate allocation	132,209	53,166	(185,375)	—
Customer related expenses	31,246	2,997	131	34,374
Energy production costs	93,748	—	—	93,748
Regulatory disallowances	8,980	—	—	8,980
Depreciation and amortization	221,780	125,915	37,230	384,925
Transmission and distribution costs	61,302	37,078	—	98,380
Taxes other than income taxes	49,807	44,441	6,332	100,580
Total operating expenses	1,097,095	411,211	9,407	1,517,713
Net other income and (deductions)	61,494	8,725	(15,399)	54,820
Interest charges	(106,018)	(58,983)	(63,065)	(228,066)
Income taxes (benefit)	29,217	27,114	(34,813)	21,518
Valencia non-controlling interest	(16,040)	—	—	(16,040)
Subsidiary preferred stock dividends	(528)	—	—	(528)
Segment earnings (loss) attributable to TXNM	$ 191,684	$ 103,528	$ (53,058)	$ 242,154
At December 31, 2024:				
Total Assets	$ 7,407,279	$ 3,649,125	$ 155,329	$ 11,211,733
Goodwill	$ 51,632	$ 226,665	$ —	$ 278,297

2023	PNM	TNMP	Corporate and Other	TXNM Consolidated
		(In thousands)		
Electric operating revenues	$ 1,403,948	$ 535,250	$ —	$ 1,939,198
Cost of energy				
Fuel burn	138,538	—	—	138,538
Purchases for resale	499,921	—	—	499,921
Transmission by others	25,155	138,647	—	163,802
Significant segment expenses				
Administrative and general - direct	52,554	2,710	139,010	194,274
Administrative and general - corporate allocation	124,321	47,470	(171,791)	—
Customer related expenses	29,775	3,783	68	33,626
Energy production costs	91,610	—	—	91,610
Regulatory disallowances	70,750	1,173	—	71,923
Depreciation and amortization	177,633	113,142	28,728	319,503
Transmission and distribution costs	61,725	36,996	—	98,721
Taxes other than income taxes	48,790	41,311	5,839	95,940
Total operating expenses	1,320,772	385,232	1,854	1,707,858
Net other income and (deductions)	41,358	8,368	(182)	49,544
Interest charges	(86,574)	(46,152)	(57,629)	(190,355)
Income taxes (benefit)	(16,758)	17,297	(16,889)	(16,350)
Valencia non-controlling interest	(18,533)	—	—	(18,533)
Subsidiary preferred stock dividends	(528)	—	—	(528)
Segment earnings (loss) attributable to TXNM	$ 35,657	$ 94,937	$ (42,776)	$ 87,818
At December 31, 2023:				
Total Assets	$ 6,813,065	$ 3,145,031	$ 294,509	$ 10,252,605
Goodwill	$ 51,632	$ 226,665	$ —	$ 278,297

Significant Segment Expenses

Reflected above are certain additional categories of operating expenses that are regularly provided to the CODM. Cost of energy consists primarily of fuel and purchase power costs for PNM and costs charged by third-party transmission providers for TNMP. Administrative and general - direct expenses are those that are incurred directly by the segment while corporate allocation are those costs that are incurred by the corporate and other segment and allocated to the utilities based on the nature of the cost incurred. Corporate allocation is eliminated in the corporate and other segment. Customer related expenses include meter reading, customer service, and bad debt expenses.

Major Customers

PNM's participation in EIM, operated by CAISO, accounted for approximately 1%, 4%, and 15% of electric operating revenues during the years ended December 31, 2025, 2024, and 2023. These revenues are passed on to customers under PNM's FPPAC with no impact to net earnings. Two REPs during the years ended December 31, 2025, 2024, and 2023 accounted for more than 10% of the electric operating revenues of TNMP as follows:

	Year Ended December 31,		
	2025	2024	2023
REP A	24 %	26 %	25 %
REP B	19	20	19

(3) Accumulated Other Comprehensive Income (Loss)

AOCI reports a measure for accumulated changes in equity that result from transactions and other economic events other than transactions with shareholders. Information regarding AOCI is as follows:

	Accumulated Other Comprehensive Income (Loss)				
	PNM			TXNM	
	Unrealized Gains on Available-for-Sale Securities	Pension Liability Adjustment	Total	Fair Value Adjustment for Cash Flow Hedges	Total
		(In thousands)			
Balance at December 31, 2022	$ 7,422	$ (81,757)	$ (74,335)	$ 8,287	$ (66,048)
Amounts reclassified from AOCI (pre-tax)	(7,199)	4,776	(2,423)	9,287	6,864
Income tax impact of amounts reclassified	1,828	(1,212)	616	(2,359)	(1,743)
Other OCI changes (pre-tax)	11,529	1,389	12,918	(15,483)	(2,565)
Income tax impact of other OCI changes	(2,928)	(353)	(3,281)	3,933	652
Net after-tax change	3,230	4,600	7,830	(4,622)	3,208
Balance at December 31, 2023	10,652	(77,157)	(66,505)	3,665	(62,840)
Amounts reclassified from AOCI (pre-tax)	(13,108)	4,866	(8,242)	10,348	2,106
Income tax impact of amounts reclassified	3,330	(1,236)	2,094	(2,629)	(535)
Other OCI changes (pre-tax)	(885)	(3,210)	(4,095)	(15,260)	(19,355)
Income tax impact of other OCI changes	225	815	1,040	3,876	4,916
Net after-tax change	(10,438)	1,235	(9,203)	(3,665)	(12,868)
Balance at December 31, 2024	$ 214	$ (75,922)	$ (75,708)	$ —	$ (75,708)

	Accumulated Other Comprehensive Income (Loss)				
	PNM			TXNM	
	Unrealized Gains on Available-for-Sale Securities	Pension Liability Adjustment	Total	Fair Value Adjustment for Cash Flow Hedges	Total
		(In thousands)			
Balance at December 31, 2024	$ 214	$ (75,922)	$ (75,708)	$ —	$ (75,708)
Amounts reclassified from AOCI (pre-tax)	(785)	64,265	63,480	—	63,480
Income tax impact of amounts reclassified	199	(16,323)	(16,124)	—	(16,124)
Other OCI changes (pre-tax)	791	2,760	3,551	(1,492)	2,059
Income tax impact of other OCI changes	(201)	(701)	(902)	379	(523)
Net after-tax change	4	50,001	50,005	(1,113)	48,892
Balance at December 31, 2025	$ 218	$ (25,921)	$ (25,703)	$ (1,113)	$ (26,816)

The Consolidated Statements of Earnings include pre-tax amounts reclassified from AOCI related to Unrealized Gains on Available-for-Sale Debt Securities in gains (losses) on investment securities, related to Pension Liability Adjustment in other (deductions), and related to Fair Value Adjustment for Cash Flow Hedges in interest charges. The income tax impacts of all amounts reclassified from AOCI are included in income taxes in the Consolidated Statements of Earnings.

(4) Electric Operating Revenues

Accounts Receivable and Allowance for Credit Losses

Accounts receivable consists primarily of trade receivables from customers. In the normal course of business, credit is extended to customers on a short-term basis. The Company estimates the allowance for credit losses on trade receivables based on historical experience and estimated default rates. Accounts receivable balances are reviewed monthly, adjustments to the allowance for credit losses are made as necessary and amounts that are deemed uncollectible are written off. In addition to the allowance for credit losses on trade receivables, the Company has evaluated other receivables for potential credit related losses. These balances include potential exposures for other non-retail utility services. In the years ended December 31, 2025, and 2024, there were no estimated credit losses related to these transactions.

Revenue Recognition

Retail electric operating revenues are recorded in the period of energy delivery, which includes estimated amounts for service rendered but unbilled at the end of each accounting period. The determination of the energy sales billed to individual retail customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading and the corresponding unbilled revenue are estimated. Unbilled electric revenue is estimated based on daily generation volumes, estimated customer usage by class, line losses, historical trends and experience, applicable customer rates or by using AMS data where available. Amounts billed are generally due within the next month. The Company does not incur incremental costs to obtain contracts for its energy services.

PNM’s wholesale electricity sales are recorded as electric operating revenues and wholesale electricity purchases are recorded as costs of energy sold. Derivative contracts that are subject to unplanned netting are recorded net in earnings. A “book-out” is the planned or unplanned netting of off-setting purchase and sale transactions. A book-out is a transmission mechanism to reduce congestion on the transmission system or administrative burden. For accounting purposes, a book-out is the recording of net revenues upon the settlement of a derivative contract.

Unrealized gains and losses on derivative contracts that are not designated for hedge accounting are classified as economic hedges. Economic hedges are defined as derivative instruments, including long-term power and fuel supply agreements, used to hedge generation assets and purchased power costs. Changes in the fair value of economic hedges are reflected in results of operations, with changes related to economic hedges on sales included in operating revenues and changes related to economic hedges on purchases included in cost of energy sold. See Note 9.

The Company has collaborative arrangements related to its interest in SJGS, Four Corners, PVNGS, and Luna. The Company has determined that during the years ended December 31, 2025, 2024, and 2023 none of the joint owners in its collaborative arrangements were customers under Topic 606. The Company will continue to evaluate transactions between collaborative arrangement participants in future periods under the revenue recognition standard.

PNM and TNMP recognize revenue as they satisfy performance obligations, which typically occurs as the customer or end-user consumes the electric service provided. Electric services are typically for a bundle of services that are distinct and transferred to the end-user in one performance obligation measured by KWh or KW. Electric operating revenues are recorded in the period of energy delivery, including estimated unbilled amounts. The Company has elected to exclude all sales and similar taxes from revenue.

Revenue from contracts with customers is recorded based upon the total authorized tariff or market price at the time electric service is rendered, including amounts billed under arrangements qualifying as an Alternative

Revenue Program ("ARP"). ARP arrangements are agreements between PNM or TNMP and its regulator that allow PNM or TNMP to adjust future rates in response to past activities or completed events, if certain criteria are met. ARP revenues are required to be reported separately from contracts with customers. ARP revenues in a given period include the recognition of "originating" ARP revenues (i.e. when the regulator-specific conditions are met) in the period, offset by the reversal of ARP revenues currently approved for recovery by the governing bodies.

Sources of Revenue

Additional information about the nature of revenues is provided below. Additional information about matters affecting PNM's and TNMP's regulated revenues is provided in Note 17.

Revenue from Contracts with Customers

PNM

NMPRC Regulated Retail Electric Service – PNM provides electric generation, transmission, and distribution service to its rate-regulated customers in New Mexico. PNM's retail electric service territory covers a large area of north central New Mexico, including the cities of Albuquerque, Rio Rancho, and Santa Fe, and certain areas of southern New Mexico. Customer rates for retail electric service are set by the NMPRC, and revenue is recognized as energy is delivered to the customer. PNM invoices customers on a monthly basis for electric service and generally collects billed amounts within one month.

Transmission Service to Third Parties – PNM owns transmission lines that are interconnected with other utilities in New Mexico, Texas, Arizona, Colorado, and Utah. Transmission customers receive service for the transmission of energy owned by the customer utilizing PNM's transmission facilities. Customers generally receive transmission services, which are regulated by FERC, from PNM through PNM's Open Access Transmission Tariff ("OATT") or a specific contract. Customers are billed based on capacity and energy components on a monthly basis. PNM owns the Western Spirit Line and services under related transmission agreements use an incremental rate, approved by FERC, that is separate from the formula rate mechanism.

Wholesale Energy Sales – PNM engages in activities to optimize its existing jurisdictional assets and long-term power agreements through spot market, hour-ahead, day-ahead, week-ahead, month-ahead, and other sales of excess generation not required to fulfill retail load and contractual commitments. PNM participates in the EIM (a real-time wholesale energy trading market operated by the CAISO) that enables participating electric utilities to buy and sell energy. The NMPRC granted PNM authority to seek recovery of costs associated with joining the EIM, which have been included in the 2024 Rate Change and to pass the benefits of participating in EIM to customers through the FPPAC. Increases in electric operating revenue resulting from PNM's participation in EIM are passed on to customers through PNM's FPPAC with no impact to net earnings.

TNMP

PUCT Regulated Retail Electric Service – TNMP provides transmission and distribution services in Texas under the provisions of TECA and the Texas Public Utility Regulatory Act. TNMP is subject to traditional cost-of-service regulation with respect to rates and service under the jurisdiction of the PUCT and certain municipalities. TNMP's transmission and distribution activities are solely within ERCOT and not subject to traditional rate regulation by FERC. TNMP provides transmission and distribution services at regulated rates to various REPs that, in turn, provide retail electric service to consumers within TNMP's service territory. Revenue is recognized as energy is delivered to the consumer. TNMP invoices REPs on a monthly basis and is generally paid within a month.

TCOS – TNMP is a transmission service provider that is allowed to recover its TCOS through a network transmission rate that is approved by the PUCT. TCOS customers are other utilities that receive service for the transmission of energy owned by the customer utilizing TNMP's transmission facilities.

Alternative Revenue Programs

The Company defers certain costs and records certain liabilities pursuant to the rate actions of the NMPRC, PUCT, and FERC. ARP revenues, which are discussed above, include recovery or refund provisions under PNM's renewable energy rider and true-ups to PNM's formula transmission rates; transmission cost recovery factor, and the impacts of the PUCT's January 25, 2018 order regarding the change in the federal corporate income tax rate; the energy efficiency incentive bonus at both PNM and TNMP; HB 5247; and PNM's TOD rate pilot program. Regulatory assets and liabilities are recognized for the difference between ARP revenues and amounts currently approved for recovery by the governing bodies. Regulatory assets and liabilities are amortized into earnings as amounts are billed. TNMP's 2018 Rate Case integrated AMS costs into base rates beginning January 1, 2019. These costs are being amortized into earnings as alternative revenues over a period of five years.

Other Electric Operating Revenues

Other electric operating revenues consist primarily of PNM's economic hedges that meet the definition of a derivative and are therefore not considered revenue from contracts with customers. Derivative revenues include gains and losses representing changes in fair value (Note 9) and settlements from sales of electricity under forward sales contracts.

Disaggregation of Revenues

A disaggregation of revenues from contracts with customers by the type of customer is presented in the table below. The table also reflects ARP revenues and other revenues.

Year Ended December 31, 2025	PNM	TNMP	TXNM Consolidated
		(In thousands)	
Electric Operating Revenues:			
Contracts with customers:			
Retail electric revenue			
Residential	$ 555,611	$ 235,356	$ 790,967
Commercial	465,639	187,965	653,604
Industrial	146,051	58,394	204,445
Public authority	24,113	8,410	32,523
Economy energy service	27,704	—	27,704
Transmission	149,669	170,061	319,730
Wholesale energy sales	97,755	—	97,755
Miscellaneous	6,336	3,860	10,196
Total revenues from contracts with customers	1,472,878	664,046	2,136,924
Alternative revenue programs	4,255	17,270	21,525
Other electric operating revenues	7,157	—	7,157
Total Electric Operating Revenues	$ 1,484,290	$ 681,316	$ 2,165,606

Year Ended December 31, 2024	PNM	TNMP	TXNM Consolidated
		(In thousands)	
Electric Operating Revenues:			
Contracts with customers:			
Retail electric revenue			
Residential	$ 541,581	$ 203,227	$ 744,808
Commercial	460,311	166,858	627,169
Industrial	123,754	35,300	159,054
Public authority	23,161	7,329	30,490
Economy energy service	25,481	—	25,481
Transmission	141,058	157,049	298,107
Wholesale energy sales	64,903	—	64,903
Miscellaneous	5,776	3,813	9,589
Total revenues from contracts with customers	1,386,025	573,576	1,959,601
Alternative revenue programs	(9,720)	18,535	8,815
Other electric operating revenues	2,783	—	2,783
Total Electric Operating Revenues	$ 1,379,088	$ 592,111	$ 1,971,199

Year Ended December 31, 2023	PNM	TNMP	TXNM Consolidated
		(In thousands)	
Electric Operating Revenues:			
Contracts with customers:			
Retail electric revenue			
Residential	$ 425,448	$ 190,953	$ 616,401
Commercial	391,964	155,254	547,218
Industrial	90,084	45,508	135,592
Public authority	21,018	6,777	27,795
Economy energy service	34,340	—	34,340
Transmission	159,475	135,831	295,306
Wholesale energy sales	248,801	—	248,801
Miscellaneous	5,676	3,739	9,415
Total revenues from contracts with customers	1,376,806 [1]	538,062	1,914,868 [1]
Alternative revenue programs	9,419	(2,812)	6,607
Other electric operating revenues	17,723	—	17,723
Total Electric Operating Revenues	$ 1,403,948	$ 535,250	$ 1,939,198

[1] Included in revenue from contracts with customers at PNM and TXNM is a $128.7 million reduction associated with the SJGS abandonment settlement and a $38.4 million reduction associated with PVNGS leased capacity as a result of the NMPRC final order in the 2024 Rate Change.

Contract Balances

Performance obligations related to contracts with customers are typically satisfied when the energy is delivered, and the customer or end-user utilizes the energy. Accounts receivable from customers represents amounts billed, including amounts under ARPs. For PNM, accounts receivable reflected on the Consolidated Balance Sheets, net of allowance for credit losses, includes $115.9 million and $94.3 million at December 31, 2025 and 2024 resulting from contracts with customers. All of TNMP's accounts receivable results from contracts with customers.

Contract assets are an entity's right to consideration in exchange for goods or services that the entity has transferred to a customer when that right is conditioned on something other than the passage of time (for example, the entity's future performance). Upon the completion of the Western Spirit Line, PNM entered into a TSA with Pattern Wind under an incremental tariff rate approved by FERC. The terms of the agreement provide for a financing component that benefits the customer. As such, the revenue that PNM recognizes will be in excess of the consideration received at the beginning of the service term resulting in a contract asset. The balance of the contract asset was $41.3 million at December 31, 2025 and $32.0 million at December 31, 2024, and is included in Other deferred charges on the Consolidated Balance Sheets.

Contract liabilities arise when consideration is received in advance from a customer before satisfying the performance obligations. Therefore, revenue is deferred and not recognized until the obligation is satisfied. Under its OATT, PNM accepts upfront consideration for capacity reservations requested by transmission customers, which requires PNM to defer the customer's transmission capacity rights for a specific period of time. PNM recognizes the revenue of these capacity reservations over the period it defers the customer's capacity rights. Other utilities pay PNM and TNMP in advance for the joint-use of their utility poles. These revenues are recognized over the period of time specified in the joint-use contract, typically for one calendar year. Deferred revenues on these arrangements are recorded as contract liabilities. TXNM's, PNM's, and TNMP's contract liabilities and related revenues are not material for any of the periods presented. The Company has no other arrangements with remaining performance obligations to which a portion of the transaction price would be required to be allocated.

(5) Earnings and Dividends Per Share

Basic earnings per share is computed by dividing net earnings attributable to TXNM by the weighted average number of common shares outstanding during the period. Diluted earnings per share was computed by dividing net earnings attributable to TXNM by the diluted weighted average number of common shares outstanding during the period. Diluted earnings per share reflect the potential dilution that could occur if securities or other agreements to issue common stock were settled. TXNM applies the treasury stock method for restricted stock, the 2022 ATM Program, the 2024 ATM Program, and the 2025 ATM Program. The if-converted method is applied in determining the potential dilutive effect of the conversion of outstanding Convertible Notes. Information regarding the computation of earnings per share and dividends per share is as follows:

	Year Ended December 31,		
	2025	2024	2023
	(In thousands, except per share amounts)		
Net Earnings Attributable to TXNM	$ 151,362	$ 242,154	$ 87,818
Average Number of Common Shares:			
Outstanding during year	101,158	90,214	86,038
Vested awards of restricted stock	349	320	258
Average Shares – Basic	101,507	90,534	86,296
Dilutive Effect of Common Stock Equivalents:			
TXNM ATM Programs	74	12	38
TXNM Convertible Notes	757	—	—
Restricted stock	54	45	35
Average Shares – Diluted	102,392	90,591	86,369
Net Earnings Attributable to TXNM Per Share of Common Stock:			
Basic	$ 1.49	$ 2.67	$ 1.02
Diluted	$ 1.48	$ 2.67	$ 1.02
Dividends Declared per Common Share	$ 1.65	$ 1.57	$ 1.49

(6) Stockholders' Equity

Common Stock and Equity Contributions

In each of the years ended December 31, 2025, 2024, and 2023, TXNM executed agreements pursuant to which it issued shares of TXNM common stock. Details of these transactions and the physical settlement of shares of TXNM common stock may be found in Note 7. Neither PNM nor TNMP issued any common stock in 2025, 2024, and 2023.

On August 2, 2024, TXNM increased the number of authorized shares of the TXNM common stock from 120,000,000 to 200,000,000.

TXNM funded cash equity contributions to PNM of $123.3 million, $55.0 million, and zero in 2025, 2024, and 2023. TXNM funded $250.0 million, $24.0 million, and $40.9 million of cash equity contributions to TNMP in 2025, 2024, and 2023.

Dividends on Common Stock

The declaration of common dividends by TXNM is dependent upon a number of factors, including the ability of TXNM's subsidiaries to pay dividends. TXNM's primary sources of dividends are its operating subsidiaries.

PNM declared and paid cash dividends to TXNM of $51.0 million in 2024 but did not declare or pay any cash dividends in 2025 or 2023. TNMP did not declare or pay any cash dividends to TXNM in 2025, 2024, or 2023.

The NMPRC has placed certain restrictions on the ability of PNM to pay dividends to TXNM, including the restriction that PNM cannot pay dividends that cause its debt rating to fall below investment grade. The NMPRC provisions allow PNM to pay dividends, with at least 15 days prior notice, from current earnings, which are determined on a rolling four quarter basis, or from equity contributions previously made by TXNM. The Federal Power Act also imposes certain restrictions on dividends by public utilities. Debt-to-capitalization ratio requirements, as discussed in Note 7, remain at less than or equal to 65% for PNM and TNMP and less than or equal to 70% for TXNM. These debt-to-capitalization ratio requirements could limit the amounts of dividends that could be paid. PNM also has other financial covenants that limit the transfer of assets, through dividends or other means, including a requirement to obtain the approval of certain financial counterparties to transfer more than five percent of PNM's assets. As of December 31, 2025, the 65% debt-to-capitalization covenant would restrict the payment of dividends from the retained earnings of PNM to $624.1 million, and the 65% debt-to-capitalization covenant would restrict the payment of dividends by TNMP to $531.9 million. Similarly, the 70% debt-to-capitalization covenant would restrict the payment of dividends by TXNM to $1.7 billion.

In addition, the ability of TXNM to declare dividends is dependent upon the extent to which cash flows will support dividends, the availability of retained earnings, financial circumstances and performance, current and future regulatory decisions, Congressional and legislative acts, and economic conditions. Conditions imposed by the NMPRC or PUCT, future growth plans and related capital requirements, and business considerations may also affect TXNM's ability to pay dividends.

Preferred Stock

PNM's cumulative preferred shares outstanding bear dividends at 4.58% per annum. PNM preferred stock does not have a mandatory redemption requirement, but may be redeemed, at PNM's option, at 102% of the stated value plus accrued dividends. The holders of the PNM preferred stock are entitled to payment before the holders of common stock in the event of any liquidation or dissolution or distribution of assets of PNM. In addition, PNM's preferred stock is not entitled to a sinking fund and cannot be converted into any other class of stock of PNM.

TXNM and TNMP have no preferred stock outstanding. The authorized shares of TXNM and TNMP preferred stock are 10 million shares and 1 million shares, respectively.

(7) Financing

The Company's financing strategy includes both short-term and long-term borrowings. The Company utilizes short-term revolving credit facilities, as well as cash flows from operations, to provide funds for both construction and operating expenditures. Depending on market and other conditions, the Company will periodically sell long-term debt or enter into term loan arrangements and use the proceeds to reduce borrowings under the revolving credit facilities or refinance other debt. Each of the Company's revolving credit facilities, term loans, and other debt agreements contain a single financial covenant that requires the maintenance of a debt-to-capitalization ratio. For the TXNM agreements this ratio must be maintained at less than or equal to 70%, and for the PNM and TNMP agreements this ratio must be maintained at less than or equal to 65%. The Company's revolving credit facilities, term loans, and other debt agreements generally also contain customary covenants, events of default, cross-default provisions, and change-of-control provisions.

PNM must obtain NMPRC approval for any financing transaction having a maturity of more than 18 months. In addition, PNM files its annual informational financing filing and short-term financing plan with the NMPRC.

Financing Activities

TXNM

At December 31, 2022, TXNM had $1.0 billion outstanding under the TXNM 2021 Delayed-Draw Term Loan, among TXNM, the lenders party thereto, and Wells Fargo Bank, N.A., as administrative agent. As discussed below on June 30, 2023, $500.0 million under the TXNM 2021 Delayed Draw Term Loan was prepaid, without penalty, with proceeds from the TXNM 2023 Term Loan. As discussed below, on June 21, 2024, proceeds from the Convertible Notes were used to prepay, without penalty, $449.0 million under the TXNM 2021 Delayed Draw Term Loan. On May 16, 2025, TXNM paid the remaining $51.0 million due under its TXNM 2021 Delayed Draw Term Loan in accordance with its terms.

On November 10, 2022, TXNM entered into a distribution agreement with BofA Securities, Inc., MUFG Securities Americas Inc. and Wells Fargo Securities, LLC, as sales agents, and Bank of America, N.A., MUFG Securities EMEA plc and Wells Fargo Bank, N.A., as forward purchasers, pursuant to which the Company may sell, from time to time, up to an aggregate
sales price of $200.0 million of its common stock, no par value, through the sales agents (the "TXNM 2022 ATM Program"). Sales of the shares made pursuant to the distribution agreement may be made in "at the market offerings" as defined in Rule 415 of the Securities Act. TXNM did not initially receive any proceeds upon the execution of this agreement.

Throughout 2023, TXNM entered into forward sale agreements, for the sale of shares of TXNM common stock. On December 15, 2023, TXNM physically settled the forward purchases under the TXNM 2022 ATM Program and used the proceeds to repay borrowings under the TXNM Revolving Credit Facility and for other corporate purposes. Cash proceeds shown below were reduced by $1.0 million in issuance costs resulting in net cash proceeds of $198.2 million.

Settlement date	Shares	Settlement price	Settlement amount
			(in thousands)
March 15, 2023	504,452	$ 49.00	$ 24,720
March 20, 2023	528,082	48.78	25,758
May 30, 2023	244,639	47.99	11,741
June 30, 2023	804,477	45.07	36,257
September 26, 2023	2,283,860	44.11	100,734
	4,365,510		$ 199,210

On June 30, 2023, TXNM entered into the $500.0 million TXNM 2023 Term Loan among TXNM, the lenders party thereto, and Wells Fargo Bank, N.A., as administrative agent. The proceeds were used to prepay an equal amount of the TXNM 2021 Delayed Draw Term Loan, without penalty. As discussed below, on June 21, 2024, proceeds from the Convertible Notes were used to prepay, without penalty, $90.0 million under the TXNM 2023 Term Loan. On June 24, 2025, proceeds from the June 2025 Stock Purchase Agreement were used to prepay, without penalty, $200.0 million under the TXNM 2023 Term Loan. On August 29, 2025, TXNM paid the remaining $210.0 million due under its TXNM 2023 Term Loan in accordance with its terms, which terminated the agreement.

On May 6, 2024, TXNM entered into a distribution agreement with BofA Securities, Inc., Citigroup Global Markets, Inc., MUFG Securities Americas Inc., RBC Capital Markets, LLC, Scotia Capital (USA) Inc., and Wells Fargo Securities, LLC, as sales agents, and Bank of America, N.A., Citibank, N.A., MUFG Securities EMEA plc, Royal Bank of Canada, The Bank of Nova Scotia, and Wells Fargo Bank, N.A., as forward purchasers, pursuant to which the Company may sell, from time to time, up to an aggregate sales amount of $100.0 million of its common stock, no par value, through the sales agents (the "TXNM 2024 ATM Program"). On August 5, 2024, subsequent to approval by shareholders to increase TXNM's authorized shares, the Company amended the distribution agreement increasing the aggregate sales amount from $100.0 million to $300.0 million of its common stock, no par value, that may be sold under the TXNM 2024 ATM Program. Sales of the shares made pursuant to the distribution agreement may be made in "at the market offerings" as defined in Rule 415 of the Securities Act. TXNM did not initially receive any proceeds upon the execution of this agreement.

Throughout 2024, TXNM entered into forward sales agreements for the sale of shares of TXNM common stock. On December 30, 2024, TXNM physically settled forward purchases under the TXNM 2024 ATM Program for 2,458,951 shares and used the proceeds to repay borrowings under the TXNM Revolving Credit Facility. Cash proceeds shown below were reduced by $0.8 million in issuance costs resulting in net cash proceeds of $98.6 million.

Settlement date	Shares	Settlement price	Settlement amount
			(in thousands)
May 13, 2024	262,025	$ 38.01	$ 9,960
August 13, 2024	113,014	40.21	4,545
August 16, 2024	261,066	40.48	10,568
August 23, 2024	284,952	40.56	11,558
August 30, 2024	311,583	40.64	12,661
September 16, 2024	1,226,311	40.85	50,093
	2,458,951		$ 99,385

On May 27, 2025, TXNM physically settled all remaining forward purchases under the TXNM 2024 ATM Program for 1,104,641 shares, aggregating net proceeds of $49.6 million, including $0.5 million for equity issuance costs. TXNM used the proceeds from the settled shares to repay borrowings under the TXNM Revolving Credit Facility. Following this settlement, no additional shares of TXNM's common stock remain subject to future settlement under the TXNM 2024 ATM Program.

On June 10, 2024, TXNM issued $500.0 million aggregate principal amount of Convertible Notes in a private offering to qualified institutional buyers pursuant to Rule 144A under the Securities Act. The Convertible Notes are unsecured obligations of the Company and rank junior and subordinate in right of payment to the prior payment in full of the Company's existing and future senior indebtedness. The Convertible Notes bear interest at a rate of 5.75% per year, payable semi-annually in arrears on June 1 and December 1, and mature on June 1, 2054, unless earlier converted, redeemed, or repurchased in accordance with their terms. On June 21, 2024, TXNM issued an additional $50.0 million aggregate principal amount of the Convertible Notes, pursuant to an overallotment option granted by TXNM to the initial purchasers of the $500.0 million Convertible Notes. Proceeds from the Convertible Notes were used to prepay $449.0 million of borrowings under the TXNM 2021 Delayed Draw Term Loan and $90.0 million of borrowings under the TXNM 2023 Term Loan, without penalty, and for other corporate purposes.

TXNM may not redeem the Convertible Notes prior to June 6, 2029, except upon the occurrence of certain tax events, rating agency events or treasury stock events (each, a "special event"). TXNM may redeem for cash all, but not less than all, of the Convertibles Notes upon the occurrence of a special event at any time, at its option, at a redemption price equal to 100% of the principal amount of the Convertible Notes to be redeemed, plus accrued and unpaid interest to, but excluding, the redemption date. In addition, TXNM may redeem for cash all or part (subject to certain limitations on partial redemptions) of the Convertible Notes, at its option, on or after June 6, 2029, at a redemption price equal to 100% of the principal amount of the convertible notes to be redeemed, plus accrued and unpaid interest to, but excluding, the redemption date, if the last reported sale price of TXNM's common stock has been at least 130% of the conversion price of the convertible notes then in effect for at least 20 trading days (whether or not consecutive) during any 30 consecutive trading day period (including the last trading day of such period) ending on, and including, the trading day immediately preceding the date on which TXNM provides notice of redemption. In each case, TXNM will not, and will not be permitted to, issue a notice of redemption, or specify a redemption date, during any interest deferral period.

Prior to the close of business on the business day immediately preceding December 1, 2053, the Convertible Notes will be convertible at the option of the holders only under certain conditions. On or after December 1, 2053, until the close of business on the second business day immediately preceding the maturity date, holders may convert all or any portion of their Convertible Notes at their option, at any time, at the conversion rate then in effect, irrespective of these conditions. Upon conversion of the Convertible Notes, TXNM will pay cash, or deliver an equal aggregate principal amount of a newly issued series of its nonconvertible junior subordinated notes with the same terms as the Convertible Notes (other than the conversion features and certain features in relation to redemption rights), in either case, up to the aggregate principal amount of the Convertible Notes being converted, and deliver shares of TXNM's common stock in respect of the remainder, if any, of TXNM's conversion obligation in excess of the aggregate principal amount of the Convertible Notes being converted.

The conversion rate and the corresponding conversion price will be subject to adjustment by certain events such as increased dividends but will not adjust for any accrued or unpaid interest. In addition, following certain corporate events that occur prior to the maturity date of the Convertible Notes or if TXNM delivers a notice of a special event redemption, TXNM will, in certain circumstances, increase the conversion rate for a holder that elects to convert its Convertible Notes in connection with such a corporate event or such notice of special event redemption, as the case may be.

TXNM issued the Convertible Notes pursuant to an indenture dated as of June 10, 2024, between TXNM and Computershare Trust Company, N.A., as trustee. The Convertible Notes are subject to continuing compliance with the representations, warranties, and covenants set forth in the indenture, which include the customary covenants discussed above. In the event of a fundamental change, as defined in the indenture, TXNM may be required to repurchase, for cash, the aggregate principal amount of Convertible Notes plus accrued interest. TXNM may not redeem the Convertible Notes prior to June 6, 2029, except upon the occurrence of a special event as defined in the indenture.

So long as no event of default with respect to the Convertible Notes has occurred and is continuing, TXNM may, at its option, defer interest payments on the Convertible Notes on one or more occasions for up to 20 consecutive semi-annual interest payment periods. During any deferral period, interest on the Convertible Notes will continue to accrue at the then-applicable interest rate on the Convertible Notes. In addition, during any deferral period, interest on deferred interest will accrue at the then-applicable interest rate on the Convertible Notes, compounded semi-annually, to the extent permitted by applicable law.

On January 2, 2026, TXNM notified holders of the Convertible Notes that the Convertible Notes are convertible, at the option of the holders, over a period beginning on January 1, 2026, and ending at the close of business on March 31, 2026, (the "First Quarter 2026 Conversion Period"). The Convertible Notes are convertible at a conversion rate of 22.5248 shares of common stock per $1,000 principal amount of Convertible Notes, which is equivalent to a conversion price of approximately $44.40 per share of common stock. On December 31, 2025, it was determined that the Convertible Notes would become convertible during the First Quarter 2026 Conversion Period because the last reported sale price of TXNM's common stock, for at least 20 trading days during the period of 30 consecutive trading days ending on, and including, the last trading day of the calendar quarter ended December 31, 2025, was greater than or equal to 130% of the conversion price in effect on each applicable trading day.

On May 18, 2025, concurrent with the execution of the Merger Agreement, TXNM entered into the May 2025 Stock Purchase Agreement whereby TXNM sold, in a private placement transaction, 8,000,000 shares of TXNM common stock for a purchase price of $50.00 per share (aggregating $400.0 million). The consummation of the May 2025 Stock Purchase Agreement occurred on June 2, 2025. TXNM used the proceeds to make cash equity contributions to TNMP, to repay borrowings under the TXNM Revolving Credit Facility, and for general corporate purposes.

On May 18, 2025, the execution of the Merger Agreement constituted a "Change of Control" under certain TXNM and TNMP debt agreements. Under each of the specified debt agreements, a "Change of Control" constitutes an "Event of Default," pursuant to which the lender parties thereto had the right to accelerate the indebtedness under the debt agreements. The definition of Change of Control under the PNM debt agreements and PNM note purchase agreements were not triggered by the execution of the Merger Agreement.

On May 23, 2025, TXNM and TNMP entered into amendments in connection with the TXNM Revolving Credit Facility, TXNM 2023 Term Loan, WFB LOC Facility, and TNMP Revolving Credit Facility with the lender parties thereto (the “Lender Consents”) to (i) amend the definition of "Change of Control" in such agreements such that the entry into the Merger Agreement would not constitute a Change of Control and (ii) waive the Event of Default arising from entry into the Merger Agreement. On December 19, 2025, in connection with exercising the available extension options (discussed below), TXNM and TNMP entered into amendments in connection with the TXNM Revolving Credit Facility and the TNMP Revolving Credit Facility to amend the definition of Change of Control permitting the closing of the Merger. The Change of Control provisions in the PNM debt agreements will not be triggered by the closing of the Merger.

To ensure sufficient liquidity pending the Lender Consents, on May 18, 2025, TXNM entered into the $910.0 million, 364-day TXNM Merger Backstop Revolving Facility between TXNM, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent. The TXNM Merger Backstop Revolving Facility was available to provide liquidity in the event the Company was unable to obtain the Lender Consents. On May 19, 2025, TXNM borrowed approximately $4.0 million under the TXNM Merger Backstop Revolving Facility and subsequently repaid the entire balance by May 21, 2025. The TXNM Merger Backstop Revolving Facility expired according to its terms as TXNM did not make any additional borrowings thereunder by the commitment termination date of May 23, 2025, and the Company was able to obtain the Lender Consents.

On June 24, 2025, TXNM entered into the June 2025 Stock Purchase Agreement whereby TXNM sold, in a private placement transaction, and the purchasers named therein agreed to purchase 3,615,003 shares of TXNM common stock for a purchase price of $55.325 per share (for an aggregate amount of approximately $200 million). The closing of the issuance occurred on June 27, 2025. TXNM used the proceeds to repay an equal amount under the TXNM 2023 Term Loan. TXNM granted the purchasers customary registration rights with respect to the shares, pursuant to which TXNM was required to register such shares for resale with the SEC. On August 8, 2025, TXNM registered the shares for resale.

On August 15, 2025, TXNM entered into a distribution agreement with BofA Securities, Inc., MUFG Securities Americas Inc., RBC Capital Markets, LLC and Scotia Capital (USA) Inc., as sales agents, and Bank of America, N.A., MUFG Securities EMEA plc, Royal Bank of Canada and The Bank of Nova Scotia, as forward purchasers, pursuant to which the Company may sell, from time to time, up to an aggregate sales price of $200.0 million of its common stock, no par value, through the sales agents (the “TXNM 2025 ATM Program”). Sales of the shares made pursuant to the distribution agreement, if any, may be made in “at the market offerings” as defined in Rule 415 of the Securities Act. TXNM did not initially receive any proceeds upon the execution of this agreement.

Beginning on August 15, 2025, TXNM sold, through the sales agents listed above, an aggregate of 3,542,377 shares of TXNM common stock as set forth in the table below and used the proceeds to repay borrowings under the TXNM Revolving Credit Facility and for other corporate purposes.

Gross cash proceeds shown below were reduced by $2.0 million in issuance costs resulting in net cash proceeds of $198.0 million.

Settlement date	Shares	Settlement price	Settlement amount
			(in thousands)
August 18, 2025	209,990	$ 56.75	$ 11,917
August 19, 2025	18,500	56.83	1,051
August 19, 2025	200,000	56.51	11,302
August 19, 2025	200,000	56.41	11,282
August 20, 2025	1,000,000	56.41	56,410
August 21, 2025	64,016	56.57	3,621
August 21, 2025	1,500,000	56.40	84,600
August 22, 2025	135,327	56.58	7,657
August 25, 2025	41,408	56.60	2,344
August 25, 2025	118,819	56.73	6,740
August 26, 2025	54,317	56.64	3,076
	3,542,377		$ 200,000

On December 10, 2025, TXNM issued $350.0 million aggregate principal amount of its TXNM 2025 Junior Subs pursuant to an indenture between the Company and U.S. Bank Trust Company, National Association, as trustee. The TXNM 2025 Junior Subs are unsecured obligations of the Company and rank junior and subordinate in right of payment to the prior payment in full of the Company's existing and future senior indebtedness. The TXNM 2025 Junior Subs rank equally in right of payment to the Convertible Notes discussed above, bear interest (subject to the Company's right to defer interest payments) at an annual rate of 7.000% per year, payable semi-annually in arrears on January 31 and July 31, and mature on July 31, 2056, unless earlier redeemed. The interest rate is subject to a periodic reset period, as defined in the indenture, to a rate that will not be below 7.000%. Proceeds from the TXNM 2025 Junior Subs were used to fund the cash equity contribution to PNM of $123.3 million, to repay borrowings under the TXNM Revolving Credit Facility, and for other corporate purposes.

TXNM may redeem the TXNM 2025 Junior Subs, at its option, before their maturity, all or part, on one or more occasions on any day in the period commencing 90 days prior to the first interest rate reset date and after the first interest rate reset date on any interest payment date, at a redemption price equal to 100% of the principal amount of the TXNM 2025 Junior Subs to be redeemed, plus accrued and unpaid interest to, but excluding, the redemption date. In addition, TXNM may redeem all, but not less than all of the TXNM 2025 Junior Subs, at a redemption price equal to 100% of the principal amount of the TXNM 2025 Junior Subs to be redeemed, plus accrued and unpaid interest to, but excluding, the redemption date, if certain changes in tax laws, treaties or interpretations occur; may redeem all, but not less than all of the TXNM 2025 Junior Subs, at a redemption price equal to 102% of the principal amount of the TXNM 2025 Junior Subs to be redeemed, plus accrued and unpaid interest to, but excluding, the redemption date, if a rating agency makes certain changes in the equity credit criteria for securities such as the TXNM 2025 Junior Subs.

PNM

At December 31, 2022, PNM had $225.0 million outstanding under the PNM 2022 Delayed-Draw Term Loan. On November 15, 2023, upon receipts of funds from the sale of energy transition property to ETBC I discussed below, PNM prepaid the $225.0 million outstanding under the PNM 2022 Delayed-Draw Term Loan, without penalty.

At December 31, 2022, PNM had $130.0 million of 1.10% PCRBs outstanding with a mandatory remarketing date of June 1, 2023, issued by Farmington with a final maturity of June 2040. On June 1, 2023, PNM remarketed the $130.0 million to new investors at 3.90% with a mandatory tender date of June 1, 2028.

At December 31, 2022, PNM had $55.0 million aggregate principal amount of its 3.15% SUNs outstanding due May 2023. On May 15, 2023, PNM repaid the $55.0 million 3.15% SUNs.

On April 28, 2023, PNM entered into the PNM 2023 Note Purchase Agreement with institutional investors for the sale and issuance of $200.0 million aggregate principal amount of two series of the PNM 2023 SUNs offered in private placement transactions. PNM issued $150.0 million of the PNM 2023 SUNs at 5.51%, due April 28, 2035, and another $50.0 million at 5.92%, due April 28, 2053. Proceeds from the PNM 2023 SUNs were used to repay borrowings under the PNM Revolving Credit Facility and the PNM New Mexico Credit Facility, for funding of capital expenditures, and for general corporate purposes. The PNM 2023 Note Purchase Agreement includes the customary covenants discussed above. In the event of a change of control, PNM will be required to offer to prepay the PNM 2023 SUNs at par. PNM has the right to redeem any or all of the PNM 2023 SUNs prior to their maturities, subject to payment of a customary make-whole premium.

On May 10, 2024, PNM entered into the $200.0 million PNM 2024 Term Loan, among PNM, the lenders party thereto and U.S. Bank National Association, as administrative agent. PNM used the proceeds of the PNM 2024 Term Loan to repay borrowings under the PNM Revolving Credit Facility, the PNM New Mexico Credit Facility, and for general corporate purposes. On November 10, 2025, the PNM 2024 Term Loan was repaid in accordance with its terms.

At December 31, 2023, PNM had outstanding $37.0 million of 3.00% PCRBs and $125.0 million of 1.15% PCRBs issued by Farmington with a mandatory remarketing date of June 1, 2024 and final maturities of June 2040 and $36.0 million of 3.00% PCRBs issued by Maricopa County, Arizona with a mandatory remarketing date of June 1, 2024 and a final maturity of January 2038. On June 3, 2024, PNM remarketed these PCRBs aggregating $198.0 million to new investors at 3.875% with a mandatory tender date of June 1, 2029.

On January 21, 2025, PNM entered into the $195.0 million PNM 2025 Term Loan, among PNM, the lenders party thereto and Canadian Imperial Bank of Commerce, New York Branch, as administrative agent. PNM used the proceeds of the PNM 2025 Term Loan to repay borrowings under the PNM Revolving Credit Facility, the PNM New Mexico Credit Facility, and for general corporate purposes. The PNM 2025 Term Loan bears interest at a variable rate, which was 4.73% at December 31, 2025, and must be repaid on or before July 21, 2026.

On April 23, 2025, PNM entered into the PNM April 2025 Note Purchase Agreement with institutional investors for the sale and issuance of $300.0 million aggregate principal amount of two series of the PNM April 2025 SUNs offered in private placement transactions. PNM issued $125.0 million of the PNM April 2025 SUNs at 5.75%, due June 1, 2032, and $175.0 million at 6.13%, due June 1, 2037. PNM used proceeds from the PNM April 2025 SUNs for the repayment of existing indebtedness, funding of capital expenditures, and general corporate purposes. The PNM April 2025 Note Purchase Agreement includes the customary covenants discussed above. In the event of a change of control, PNM will be required to offer to prepay the PNM April 2025 SUNs at par. Although there are customary change of control provisions in the PNM debt agreements, the change of control provisions in the agreements, including the PNM April 2025 Note Purchase Agreement, are not triggered by the closing of the Merger. PNM has the right to redeem any or all of the PNM April 2025 SUNs prior to their maturities, subject to payment of a customary make-whole premium.

On July 31, 2025, PNM entered into the PNM July 2025 Note Purchase Agreement with institutional investors for the sale and issuance of $350.0 million aggregate principal amount of two series of the PNM July 2025 SUNs offered in private placement transactions. On July 31, 2025, PNM issued $200.0 million of the PNM July 2025 SUNs at 5.47%, due July 31, 2031, and $150.0 million at 6.03%, due July 31, 2036. PNM used the proceeds from the PNM July 2025 SUNs to repay the PNM $250.0 million SUNs and for general corporate purposes. The PNM July 2025 Note Purchase Agreement includes the customary covenants discussed above. In the event of a change of control, PNM will be required to offer to prepay the PNM July 2025 SUNs at par. Although there are customary change of control provisions in the PNM debt agreements, the change of control provisions in the agreements, including the PNM July 2025 Note Purchase Agreement, will not be triggered by the closing of the Merger. PNM has the right to redeem any or all of the PNM July 2025 SUNs prior to their maturities, subject to payment of a customary make-whole premium.

On November 10, 2025, PNM entered into the $120.0 million PNM November 2025 Term Loan, among PNM, the lenders party thereto and U.S. Bank National Association, as administrative agent. PNM used the proceeds of the PNM November 2025 Term Loan to partially repay borrowings under the PNM 2024 Term Loan. The PNM November 2025 Term Loan bears interest at a variable rate, which was 4.67% at December 31, 2025, and must be repaid on or before May 10, 2027.

At December 31, 2025, PNM had a shelf registration statement, which was set to expire in May 2026, with capacity for the issuance of up to $650.0 million of SUNs. On February 20, 2026, PNM filed a post-effective amendment to the registration statement to deregister any and all securities that remained unsold, effectively terminating all offerings of the securities pursuant to the registration statement.

ETBC I

On November 15, 2023, ETBC I issued $343.2 million aggregate principal amount of its senior secured energy transition bonds, Series A ("ETBC I Securitized Bonds") in two tranches. The first tranche of $175.0 million aggregate principal amount was issued at an interest rate of 5.64% with an expected final payment due in August 2040. The second tranche of $168.2 million aggregate principal amount was issued at an interest rate of 6.03% with an expected final payment due in August 2048. Each tranche is subject to fixed, scheduled, semi-annual payments of principal and interest due on August 15 and February 15, with $7.3 million and 6.9 million included as Current installments of long-term debt on the Consolidated Balance Sheets at December 31, 2025 and 2024. The ETBC I Securitized Bonds were offered pursuant to a prospectus dated November 7, 2023, and are governed by an indenture between ETBC I and U.S. Bank Trust Company, National Association, as indenture trustee dated as of November 15, 2023. ETBC I used the proceeds from the issuance of the ETBC I Securitized Bonds to purchase energy transition property (Note 16) from PNM. See Note 10.

TNMP

On April 28, 2023, TNMP entered into the TNMP 2023 Bond Purchase Agreement with institutional investors for the sale of $185.0 million aggregate principal amount of two series of the TNMP 2023 Bonds offered in private placement transactions. TNMP issued the first series of $130.0 million on April 28, 2023, at a 5.01% interest rate, due April 28, 2033. The second series of $55.0 million was issued on July 28, 2023, at a 5.47% interest rate, due July 28, 2053. The proceeds were used to repay borrowings under the TNMP Revolving Credit Facility, for funding of capital expenditures, and for other corporate purposes. The TNMP 2023 Bonds are subject to continuing compliance with the representations, warranties and covenants set forth in the supplemental indentures governing the TNMP 2023 Bonds. The terms of the supplemental indentures governing the TNMP 2023 Bonds include the customary covenants discussed above. In the event of a change of control, TNMP will be required to offer to prepay the TNMP 2023 Bonds at par. TNMP has the right to redeem any or all of the TNMP 2023 Bonds prior to their maturity, subject to payment of a customary make-whole premium.

On March 28, 2024, TNMP entered into the TNMP 2024 Bond Purchase Agreement with institutional investors for the sale of $285.0 million aggregate principal amount of four series of the TNMP 2024 Bonds offered in private placement transactions. TNMP issued the first two series on March 28, 2024, consisting of $32.0 million at a 5.26% interest rate, due March 28, 2029, and $85.0 million at a 5.55% interest rate, due March 28, 2036. The third and fourth series were issued on July 1, 2024, consisting of $40.0 million at a 5.65% interest rate, due July 1, 2039, and $128.0 million at a 5.79% interest rate, due July 1, 2054. The proceeds were used to repay existing debt, including the $80.0 million of 4.03% TNMP FMBs that were due July 2024 and borrowings under the TNMP Revolving Credit Facility, for funding of capital expenditures, and for other corporate purposes. The TNMP 2024 Bonds are subject to continuing compliance with the representations, warranties and covenants set forth in the supplemental indentures governing the TNMP 2024 Bonds. The terms of the supplemental indentures governing the TNMP 2024 Bonds include the customary covenants discussed above. In the event of a change of control, TNMP will be required to offer to prepay the TNMP 2024 Bonds at par. TNMP has the right to redeem any or all of the TNMP 2024 Bonds prior to their maturity, subject to payment of a customary make-whole premium.

On February 14, 2025, TNMP entered into the TNMP February 2025 Bond Purchase Agreement with institutional investors for the sale of $140.0 million aggregate principal amount of its 5.19% TNMP February 2025 Bonds offered in private placement transactions. TNMP issued all $140.0 million of the TNMP February 2025 bonds, due April 1, 2031. The proceeds were used to repay borrowings under the TNMP Revolving Credit Facility, for funding of capital expenditures, and for other corporate purposes. The TNMP February 2025 Bonds are subject to continuing compliance with the representations, warranties and covenants set forth in the supplemental indentures governing the TNMP February 2025 Bonds. The terms of the supplemental indentures governing the TNMP February 2025 Bonds include the customary covenants discussed above. In the event of a change of control, TNMP will be required to offer to prepay the TNMP February 2025 Bonds at par. TNMP has the right to redeem any or all of the TNMP February 2025 Bonds prior to their maturity, subject to payment of a customary make-whole premium.

On May 18, 2025, concurrent with the execution of the TXNM Merger Backstop Revolving Facility, TNMP entered into the $1,505.0 million, 364-day TNMP Merger Backstop Term Loan between TNMP, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent. The TNMP Merger Backstop Term Loan was available to provide liquidity to repurchase TNMP's FMBs that were tendered for prepayment pursuant to the Offer. On July 21, 2025, TNMP issued the TNMP July 2025 FMBs and used the proceeds to repay the outstanding principal balance under the TNMP Merger Backstop Term Loan on July 22, 2025, terminating that agreement.

The documents governing an aggregate $1,505.0 million of TNMP's outstanding FMBs ("TNMP FMBs") obligated TNMP to offer ("the Offer"), within 30 business days following the signing of the Merger Agreement, to prepay the outstanding TNMP FMBs at 100% of the principal amount, plus accrued and unpaid interest thereon, but without any make-whole amount or other premium. On June 14, 2025, the Offer expired and $1,084.3 million in aggregate principal amount of the bonds were validly tendered. TNMP accepted for purchase all validly tendered bonds. On June 24, 2025, holders whose bonds were validly tendered and accepted for purchase received 100% of the aggregate principal amount of bonds prepaid plus accrued and unpaid interest using funds drawn under the TNMP Merger Backstop Term Loan, discussed above. On November 6, 2025, TNMP entered into an agreement and supplemental indenture to amend the documents governing $417.7 million of TNMP FMBs. The supplemental indenture amends the requirement for TNMP to provide certain financial reports and amends the definition of change of control such that TNMP will no longer be required to make an offer to prepay the aggregate $417.7 million TNMP FMBs upon closing of the Merger.

The documents governing an aggregate $3.0 million of TNMP FMBs still require TNMP to make another offer, within 30 business days of closing of the Merger, to prepay the remaining outstanding TNMP FMBs, totaling $3.0 million, at par. TNMP will make such offer to prepay the TNMP FMBs in accordance with the terms of the TNMP FMBs; however, holders of the TNMP FMBs are not required to tender their TNMP FMBs and may accept or reject such offer to prepay.

The information in this Form 10-K is for informational purposes only and is neither an offer to purchase, nor a solicitation of an offer to sell, subscribe for or buy any securities in any jurisdiction pursuant to the proposed transactions or otherwise, nor shall there be any sale, issuance or transfer of securities in any jurisdiction in contravention of applicable law. Similar to the offer to prepay made after signing the Merger Agreement, the post-Merger closing offer to prepay the TNMP FMBs will be made only pursuant to an offer to prepay, which will set forth the terms and conditions of the offer to prepay.

On July 21, 2025, TNMP entered into the TNMP July 2025 Bond Purchase Agreement with institutional investors for the sale of $1,084.3 million aggregate principal amount of six series of the TNMP July 2025 FMBs offered in private placement transactions. TNMP issued the TNMP July 2025 FMBs on July 21, 2025, with the following terms:

Principal Amount	Interest Rate	Due Date
(in thousands)		
$ 245,000	4.83 %	July 31, 2030
245,000	5.12	July 31, 2032
240,000	5.44	July 31, 2035
100,000	5.54	July 31, 2037
154,300	5.93	July 31, 2045
100,000	6.02	July 31, 2055
$ 1,084,300		

The proceeds were used to repay borrowings under the TNMP Merger Backstop Term Loan. The TNMP July 2025 FMBs are subject to continuing compliance with the representations, warranties, and covenants set forth in the governing supplemental indentures. In the event of certain changes of control of TNMP, TNMP will be required to offer to prepay the TNMP July 2025 FMBs at par. Although there are customary change of control provisions in the TNMP July 2025 FMBs, the change of control provisions will not be triggered by the closing of the Merger. TNMP has the right to redeem any or all of the TNMP July 2025 FMBs prior to their maturity, subject to payment of a customary make-whole premium.

On November 18, 2025, TNMP entered into the TNMP November 2025 Bond Purchase Agreement with institutional investors for the sale of $70.0 million aggregate principal amount of its 4.69% TNMP November 2025 FMBs offered in private placement transactions. On December 18, 2025, TNMP issued all $70.0 million at a 4.69% interest rate, due December 18, 2031. The proceeds were used to repay borrowings under the TNMP Revolving Credit Facility, for funding of capital expenditures, and for other corporate purposes. The TNMP November 2025 FMBs are subject to continuing compliance with the representations, warranties, and covenants set forth in the governing supplemental indentures. In the event of certain changes of control of TNMP, TNMP will be required to offer to prepay the TNMP November 2025 FMBs at par. Although there are customary change of control provisions in the TNMP November 2025 FMBs, the change of control provisions will not be triggered by the closing of the Merger. TNMP has the right to redeem any or all of the TNMP November 2025 FMBs prior to their maturity, subject to payment of a customary make-whole premium.

Hedging Activities

On June 30, 2025, TXNM executed a series of treasury lock agreements, with terms ranging from 5 years to 30 years, aggregating a total notional amount of $730.0 million to reduce interest rate exposure on the TNMP July 2025 FMBs that were issued in July 2025. The treasury lock agreements had an average fixed rate of 4.18% and TXNM designated them as cash flow hedges, measured at fair value, which was recorded as a loss of $2.5 million in Other current liabilities at June 30, 2025. Fair values, provided by an external pricing service, were determined using Level 2 inputs of quoted prices for similar agreements in active markets. On July 1, 2025, TXNM terminated all of the treasury lock agreements, realizing a pre-tax net loss of $1.6 million recorded in Accumulated other comprehensive income. The loss will be amortized through interest expense over a range of 5 to 30 years, in accordance with the terms of the TNMP July 2025 FMBs issued July 21, 2025.

TXNM entered into hedging agreements that establish a fixed rate for the indicated amount of variable rate debt, above which a customary spread is applied, which is subject to change if there is a change in TXNM’s credit rating. As of January 1, 2024, TXNM’s hedging agreements were as follows:

Effective Date	Maturity Date	Variable Rate Debt Hedged	Established Fixed Rate
		(In millions)	(Percent)
January 1, 2024	December 31, 2024	$ 100.0	3.32 %
January 1, 2024	December 31, 2024	100.0	3.32
January 1, 2024	December 31, 2024	100.0	3.38
January 1, 2024	December 31, 2024	150.0	3.62
January 1, 2024	December 31, 2024	150.0	3.57
January 1, 2025	December 31, 2025	100.0	4.18
January 1, 2025	December 31, 2025	100.0	4.18
January 1, 2025	December 31, 2025	100.0	3.99

These hedging agreements were accounted for as cash flow hedges. In November 2024, TXNM unwound and settled the $300.0 million of hedging agreements that were expected to mature on December 31, 2025, and on December 31, 2024, the remaining $600.0 million of hedging agreements matured. TXNM had no remaining active hedging agreements at December 31, 2025 or 2024.

Borrowing Arrangements Between TXNM and its Subsidiaries

TXNM has intercompany loan agreements with its subsidiaries. Individual subsidiary loan agreements vary in amount up to $150.0 million and have either reciprocal or non-reciprocal terms. Interest charged to the subsidiaries is equivalent to interest paid by TXNM on its short-term borrowings or the money-market interest rate if TXNM does not have any short-term borrowings outstanding. All balances outstanding under intercompany loan agreements are eliminated upon consolidation. See Note 1. PNM and TNMP had no borrowings from TXNM at December 31, 2025 and 2024. PNMR Development had $15.9 million and zero in short-term borrowings outstanding from TXNM at December 31, 2025 and 2024. TXNM had zero and $1.5 million in short-term borrowings outstanding from PNMR Development at December 31, 2025 and 2024.

Short-term Debt and Liquidity

As of December 31, 2025, the TXNM Revolving Credit Facility had a financing capacity of $300.0 million, and the PNM Revolving Credit Facility had a financing capacity of $400.0 million. On April 1, 2024, TXNM and PNM amended their respective revolving credit facilities, extending their maturity to March 30, 2029, with two one-year extension options that, if exercised, would extend the maturity to March 2031, subject to approval by a majority of the lenders. On December 19, 2025, the first of these one-year extension options was exercised, extending the maturities to March 29, 2030, however, one lender in each of the revolving credit facilities failed to agree to the extension. As a result, effective March 30, 2029, the TXNM Revolving Credit Facility capacity will adjust to $265.4 million, and the PNM Revolving Credit Facility capacity will adjust to $354.1 million. PNM also has the $40.0 million PNM New Mexico Credit Facility with a maturity of May 20, 2026. On July 25, 2025, PNM amended its PNM New Mexico Credit Facility to, among other things, extend the maturity from May 20, 2026 to May 31, 2030. As of December 31, 2023, the TNMP Revolving Credit Facility had a capacity of $100.0 million, secured by $100.0 million aggregate principal amount of TNMP first mortgage bonds. On April 1, 2024, TNMP entered into a new $200.0 million Revolving Credit Facility that replaced the $100.0 million Revolving Credit Facility. That new $200.0 million Revolving Credit Facility was secured by $200.0 million aggregate principal amount of TNMP first mortgage bonds and had a maturity of March 30, 2029, with two one-year extension options that, if exercised, would extend the maturity to March 2031, subject to approval by a majority of the lenders. On December 19, 2025, TNMP amended the TNMP Revolving Credit Facility to increase the capacity to $300.0 million, secured by $300.0 million aggregate principal amount of TNMP first mortgage bonds, and exercised the first of two one-year extension options, extending the maturity to March 29, 2030. One lender failed to agree to the extension and as a result, effective March 30, 2029, the TNMP Revolving Credit Facility capacity will adjust to $277.0 million. Variable interest rates under the TXNM, PNM, and TNMP revolving credit facilities are based on SOFR.

Short-term debt outstanding consists of:

Short-term Debt	December 31, 2025	December 31, 2024
	(In thousands)	
PNM:		
PNM Revolving Credit Facility	$ 138,800	$ 323,800
PNM New Mexico Credit Facility	40,000	40,000
	178,800	363,800
TNMP Revolving Credit Facility	—	151,600
TXNM Revolving Credit Facility	2,600	93,900
	$ 181,400	$ 609,300

In addition to the above borrowings, TXNM, PNM, and TNMP had letters of credit outstanding of $3.1 million, zero, and zero at December 31, 2025, that reduce the available capacity under their respective revolving credit facilities. TXNM also had $19.3 million of letters of credit outstanding under the WFB LOC Facility. At December 31, 2025, interest rates on outstanding borrowings were 5.04% for the PNM Revolving Credit Facility, 5.08% for the PNM New Mexico Credit Facility, and 5.16% for the TXNM Revolving Credit Facility. There were no borrowings outstanding under the TNMP Revolving Credit Facility at December 31, 2025.

Long-Term Debt

Information concerning long-term debt outstanding and unamortized (premiums), discounts, and debt issuance costs is as follows:

	December 31, 2025		December 31, 2024	
	Principal	Unamortized Discounts, (Premiums), and Issuance Costs, net	Principal	Unamortized Discounts, (Premiums), and Issuance Costs, net
	(In thousands)			
PNM Debt				
ETBC I - Senior Secured Energy Transition Bonds				
Series A-1, 5.64%	$ 165,565	$ 961	$ 172,471	$ 1,025
Series A-2, 6.03%	168,200	968	168,200	1,014
Senior Unsecured Notes, Pollution Control Revenue Bonds:				
2.15% due April 2033	146,000	646	146,000	736
0.875% mandatory tender - October 1, 2026	100,345	110	100,345	257
3.90% due June 2040, mandatory tender - June 1, 2028	130,000	563	130,000	796
3.875% due June 2040, mandatory tender - June 1, 2029	162,000	903	162,000	1,158
3.875% due January 2038, mandatory tender - June 1, 2029	36,000	201	36,000	258
Senior Unsecured Notes:				
3.45% due May 2025	—	—	104,000	39
3.85% due August 2025	—	—	250,000	174
3.68% due May 2028	88,000	147	88,000	209
3.78% due August 2028	15,000	27	15,000	38
3.93% due May 2033	38,000	131	38,000	149
4.22% due May 2038	45,000	196	45,000	212
4.50% due May 2048	20,000	105	20,000	110
4.60% due August 2048	85,000	450	85,000	470
3.21% due April 2030	150,000	692	150,000	852
3.57% due April 2039	50,000	370	50,000	398
2.59% due July 2033	80,000	289	80,000	328
3.14% due July 2041	80,000	358	80,000	381
2.29% due December 2031	50,000	176	50,000	205
2.97% due December 2041	100,000	469	100,000	499
5.51% due April 2035	150,000	703	150,000	779
5.92% due April 2053	50,000	270	50,000	280
5.75% due June 2032	125,000	627	—	—
6.13% due June 2037	175,000	915	—	—
6.03% due July 2036	150,000	810	—	—
5.47% due July 2031	200,000	1,041	—	—
PNM 2024 $200.0 Million Term Loan due November	—	—	200,000	57
PNM 2025 $195.0 Million Term Loan due July 2026	195,000	—	—	—
PNM 2025 $120.0 Million Term Loan due May 2027	120,000	85	—	—
	2,874,110	12,213	2,470,016	10,424
Less current maturities	302,648	110	560,907	270
	2,571,462	12,103	1,909,109	10,154

TNMP Debt

First Mortgage Bonds:				
6.95% due April 2043	93,198	(12,340)	93,198	(13,056)
3.53% due February 2026	—		60,000	91
3.22% due August 2027	—		60,000	152
3.85% due June 2028	—		60,000	219
3.79% due March 2034	—		75,000	347
3.92% due March 2039	26,900	135	75,000	401
4.06% due March 2044	19,600	108	75,000	433
3.60% due July 2029	1,000	3	80,000	270
2.73% due April 2030	2,000	9	85,000	445
3.36% due April 2050	1,900	15	25,000	210
2.93% due July 2035	6,000	38	25,000	175
3.36% due July 2050	1,300	11	50,000	424
2.44% due August 2035	—		65,000	382
4.13% due May 2052	45,000	274	65,000	409
3.81% due July 2032	2,000	9	95,000	505
5.01% due April 2033	44,000	183	130,000	610
5.47% due July 2053	11,000	55	55,000	286
5.26% due March 2029	32,000	145	32,000	189
5.55% due March 2036	40,000	233	85,000	538
5.65% due July 2039	40,000	238	40,000	256
5.79% due July 2054	48,000	303	128,000	833
5.19% due April 2031	100,000	588	—	—
4.83% due July 2030	245,000	1,183	—	—
5.12% due July 2032	245,000	1,209	—	—
5.44% due July 2035	240,000	1,203	—	—
5.54% due July 2037	100,000	504	—	—
5.93% due July 2045	154,300	787	—	—
6.02% due July 2055	100,000	513	—	—
4.69% due December 2031	70,000	525	—	—
	1,668,198	(4,069)	1,458,198	(5,881)
Less current maturities	—	—	—	—
	1,668,198	(4,069)	1,458,198	(5,881)

	December 31, 2025		December 31, 2024	
	Principal	Unamortized Discounts, (Premiums), and Issuance Costs, net	Principal	Unamortized Discounts, (Premiums), and Issuance Costs, net
	(In thousands)			
TXNM Debt				
TXNM 2021 Delayed-Draw Term Loan due May 2025	—	—	51,000	34
TXNM 2023 Term Loan due June 2026	—	—	410,000	441
5.75% TXNM Junior Subordinated Convertible Notes due June 2054	550,000	11,514	550,000	10,828
7.00% TXNM 2025 Junior Subordinated Notes due July 2056	350,000	4,086	—	—
	900,000	15,600	1,011,000	11,303
Less current maturities	—	—	51,000	34
	900,000	15,600	960,000	11,269
Total Consolidated TXNM Debt	5,442,308	23,744	4,939,214	15,846
Less current maturities	302,648	110	611,907	304
	$5,139,660	$ 23,634	$4,327,307	$ 15,542

Reflecting mandatory tender dates, long-term debt maturities as of December 31, 2025, are follows:

	TXNM	PNM	TNMP	TXNM Consolidated
	(In thousands)			
2026	$ —	$ 302,648	$ —	$ 302,648
2027	—	127,721	—	127,721
2028	—	241,162	—	241,162
2029	—	206,629	33,000	239,629
2030	—	159,123	247,000	406,123
Thereafter	900,000	1,836,827	1,388,198	4,125,025
Total	$ 900,000	$ 2,874,110	$ 1,668,198	$ 5,442,308

(8) Lease Commitments

The Company enters into various lease agreements to meet its business needs and to satisfy the needs of its customers. The Company accounts for contracts that convey the use and control of identified assets for a period of time as leases. The Company classifies leases as operating or financing by evaluating the terms of the lease agreement. Agreements under which the Company is likely to utilize substantially all of the economic value or life of the asset or that the Company is likely to own at the end of the lease term, either through purchase or transfer of ownership, are classified as financing leases. Leases not meeting these criteria are accounted for as operating leases. Agreements under which the Company is a lessor are insignificant. TXNM, PNM, and TNMP determine present value for their leases using their incremental borrowing rates at the commencement date of the lease or, when readily available, the rate implicit in the agreement. The Company leases office buildings, vehicles, energy storage facilities, and other equipment. In addition, PNM had lease interests in PVNGS and certain rights-of-way agreements that are classified as leases. All of the Company's leases with fixed-payment terms in excess of one year are recorded on the Consolidated Balance Sheets by recording a present value lease liability and a corresponding right-of-use asset. Operating lease expense is recognized within operating expenses according to the use of the asset on a straight-line basis. Financing lease costs, which are comprised primarily of fleet and office equipment leases commencing after January 1, 2019, are recognized by amortizing the right-of-use asset on a straight-line basis and by recording interest expense on the lease liability. Financing lease right-of-use assets amortization is reflected in depreciation and amortization and interest on financing lease liabilities is reflected as interest charges on the Company's Consolidated Statements of Earnings.

PVNGS

In 1985 and 1986, PNM entered into leases for its interest in PVNGS Unit 1 and 2. The leases initially were scheduled to expire in January 2015 for four Unit 1 leases and January 2016 for four Unit 2 leases. Following procedures set forth in the PVNGS leases, PNM notified four of the lessors under the Unit 1 leases and one lessor under the Unit 2 lease that it would elect to renew those leases on the expiration date of the original leases. The four Unit 1 leases expired in January 2023 and the one Unit 2 lease expired in January 2024. PNM has no further lease payments related to PVNGS Unit 1 or 2.

On April 5, 2021, PNM and Salt River Project entered into an Asset Purchase and Sale Agreement, pursuant to which PNM agreed to sell to Salt River Project certain PNM-owned assets and nuclear fuel necessary to the ongoing operation and maintenance of leased capacity in PVNGS Unit 1 and Unit 2. In January 2023, the Unit 1 leases expired, and PNM closed on the associated sale to Salt River Project, receiving payments of $33.7 million, of which $28.4 million was recorded as a reduction to Net utility plant on the Consolidated Balance Sheets and is presented as cash flows from investing activities on the Consolidated Statement of Cash Flows. In addition, $5.3 million was recorded as a reduction to materials, supplies, and fuel stock on the Consolidated Balance Sheets and is presented as cash flows from operating activities on the Consolidated Statement of Cash Flows. In January 2024, the Unit 2 leases expired, and PNM closed on the associated sale to Salt River Project, receiving payments of $3.4 million, of which $2.8 million was recorded as a reduction to Net utility plant on the Consolidated Balance Sheets and is presented as cash flows from investing activities on the Consolidated Statement of Cash Flows. In addition, $0.6 million was recorded as a reduction to Materials, supplies and fuel stock on the Consolidated Balance Sheets and is presented as cash flows from operating activities on the Consolidated Statement of Cash Flows.

Land Easements and Rights-of-Ways

Many of PNM’s electric transmission and distribution facilities are located on lands that require the grant of rights-of-way from governmental entities, Native American tribes, or private parties. PNM has completed several renewals of rights-of-way, the largest of which is a renewal with the Navajo Nation. PNM is obligated to pay the Navajo Nation annual payments of $6.0 million, subject to adjustment each year based on the Consumer Price Index, through 2029. PNM’s April 2025 payment for the amount due under the Navajo Nation right-of-way lease was $8.8 million, which included amounts due under the Consumer Price Index adjustment. Changes in the Consumer Price Index subsequent to January 1, 2019, are considered variable lease payments.

PNM has other prepaid rights-of-way agreements that are not accounted for as leases or recognized as a component of plant in service. PNM reflects the unamortized balance of these prepayments in other deferred charges on the Consolidated Balance Sheets and recognizes amortization expense associated with these agreements in the Consolidated Statement of Earnings over their term. As of December 31, 2025 and 2024, the unamortized balance of these rights-of-ways was $69.2 million and $67.1 million. During the years ended December 31, 2025, 2024, and 2023, PNM recognized amortization expense associated with these agreements of $4.5 million, $4.3 million, and $3.5 million.

Fleet Vehicles and Equipment

Fleet vehicle and equipment leases commencing on or after January 1, 2019, are classified as financing leases. Fleet vehicle and equipment leases existing as of December 31, 2018, are classified as operating leases. The Company’s fleet vehicle and equipment lease agreements include non-lease components for insignificant administrative and other costs that are billed over the life of the agreement. At December 31, 2025, residual value guarantees on fleet vehicle and equipment leases are $0.7 million, $0.5 million, and $1.2 million for PNM, TNMP, and TXNM Consolidated.

Energy Storage Agreements

The Company has ESAs with fixed payments over the life of the agreements, that are accounted for as operating leases, for which the Company records the initial lease liabilities and corresponding right-of-use assets. In the third quarter of 2025, an energy storage facility with an aggregate capacity of 50 MW began commercial operation and PNM recorded lease liabilities with a corresponding right-of-use asset of $57.8 million. The

Company also has ESAs with monthly payments that vary, depending on the available capacity of the energy storage facility, that are also accounted for as operating leases. However, due to the variable nature of the consideration, these agreements do not require a lease liability or a right-of-use asset to be recorded upon inception. Expenses for this type of lease are reflected in variable lease expense in the tables below. During the fourth quarter of 2025, two existing fixed payment ESAs were amended to variable payments based on available capacity, resulting in a $208 million retirement of unamortized right-of-use assets and associated lease liabilities. In addition, the Company has elected to separate lease components from non-lease components for ESAs and accordingly does not include non-lease components in the measurement of the lease liability or right-of-use asset. The non-lease components which are not included in the measurement of the lease liability or the corresponding right-of-use asset, comprises of 25.5% of the value of the agreements.

Information related to the Company's operating leases recorded on the Consolidated Balance Sheets is presented below:

	December 31, 2025			December 31, 2024		
	PNM	TNMP	TXNM Consolidated	PNM	TNMP	TXNM Consolidated
			(In thousands)			
Operating leases:						
Operating lease assets, net of amortization	$107,986	$ 39	$ 108,517	$271,433	$ 923	$ 272,894
Current portion of operating lease liabilities	8,913	15	8,969	13,542	713	14,293
Long-term portion of operating lease liabilities	96,246	24	96,735	254,702	167	255,376

As discussed above, the Company classifies its fleet vehicle and equipment leases and its office equipment leases commencing on or after January 1, 2019, as financing leases.

Information related to the Company's financing leases recorded on the Consolidated Balance Sheets is presented below:

	December 31, 2025			December 31, 2024		
	PNM	TNMP	TXNM Consolidated	PNM	TNMP	TXNM Consolidated
			(In thousands)			
Financing leases:						
Non-utility property	$ 30,555	$ 33,344	$ 65,366	$ 24,548	$ 24,420	$ 50,144
Accumulated depreciation	(13,079)	(14,319)	(27,928)	(10,997)	(13,411)	(24,604)
Non-utility property, net	$ 17,476	$ 19,025	$ 37,438	$ 13,551	$ 11,009	$ 25,540
Other current liabilities	$ 5,764	$ 6,604	$ 12,743	$ 4,311	$ 4,527	$ 9,126
Other deferred credits	11,740	12,456	24,786	9,262	6,504	16,470

Information concerning the weighted average remaining lease terms and the weighted average discount rates used to determine the Company's lease liabilities is presented below:

	December 31, 2025			December 31, 2024		
	PNM	TNMP	TXNM Consolidated	PNM	TNMP	TXNM Consolidated
Weighted average remaining lease term (years):						
Operating leases	15.64	2.63	15.60	17.52	1.10	17.45
Financing leases	3.75	3.48	3.59	3.51	2.80	3.20
Weighted average discount rate:						
Operating leases	5.55 %	5.39 %	5.55 %	5.68 %	4.41 %	5.68 %
Financing leases	5.33	5.43	5.37	5.08	5.19	5.12

Information for the components of lease expense is as follows:

	Year Ended December 31, 2025		
	PNM	TNMP	TXNM Consolidated
	(In thousands)		
Operating lease cost:			
Energy storage leases	$ 21,972	$ —	$ 21,972
Other operating leases	7,441	434	7,950
Amounts capitalized	(33)	(339)	(372)
Total operating lease expense	29,380	95	29,550
Financing lease cost:			
Amortization of right-of-use assets	5,132	6,227	11,720
Interest on lease liabilities	785	821	1,659
Amounts capitalized	(3,856)	(5,859)	(9,715)
Total financing lease expense	2,061	1,189	3,664
Variable lease expense	27,629	—	27,629
Short-term lease expense	721	25	848
Total lease expense for the period	$ 59,791	$ 1,309	$ 61,691

	Year Ended December 31, 2024		
	PNM	TNMP	TXNM Consolidated
	(In thousands)		
Operating lease cost			
Energy storage leases	$ 13,353	$ —	$ 13,353
Other operating leases	7,722	907	8,679
Amounts capitalized	(101)	(793)	(894)
Total operating lease expense	20,974	114	21,138
Financing lease cost:			
Amortization of right-of-use assets	4,554	5,129	9,889
Interest on lease liabilities	603	595	1,229
Amounts capitalized	(3,227)	(4,648)	(7,875)
Total financing lease expense	1,930	1,076	3,243
Variable lease expense	3,900	—	3,900
Short-term lease expense	714	23	787
Total lease expense for the period	$ 27,518	$ 1,213	$ 29,068

	Year Ended December 31, 2023		
	PNM	TNMP	TXNM Consolidated
	(In thousands)		
Operating lease cost			
Energy Storage leases	$ 4,351	$ —	$ 4,351
Other operating leases	11,127	1,479	12,606
Amounts capitalized	(374)	(1,298)	(1,672)
Total operating lease expense	15,104	181	15,285
Financing lease cost:			
Amortization of right-of-use assets	4,566	4,634	9,253
Interest on lease liabilities	562	497	1,060
Amounts capitalized	(3,190)	(4,250)	(7,440)
Total financing lease expense	1,938	881	2,873
Variable lease expense	1,342	—	1,342
Short-term lease expense	675	29	782
Total lease expense for the period	$ 19,059	$ 1,091	$ 20,282

Supplemental cash flow information related to the Company's leases is as follows:

	Year Ended December 31, 2025			Year Ended December 31, 2024		
	PNM	**TNMP**	**TXNM Consolidated**	**PNM**	**TNMP**	**TXNM Consolidated**
	(In thousands)					
Cash paid for amounts included in the measurement of lease liabilities:						
Operating cash flows from operating leases	$ 29,018	$ 63	$ 29,147	$ 21,277	$ 47	$ 21,368
Operating cash flows from financing leases	270	185	507	206	102	340
Financing cash flows from financing leases	1,783	1,007	3,137	1,707	971	2,872
Non-cash information related to right-of-use assets obtained or retired in exchange for lease obligations:						
Operating leases additions	$ 57,923	$ 9	$ 57,932	$101,594	$ 100	$ 102,261
Operating leases retirements	(207,774)	(475)	(208,249)	38	(138)	(117)
Financing leases additions	9,182	14,360	23,861	4,962	3,715	9,850

Capitalized lease costs are reflected as investing activities on the Company's Consolidated Statements of Cash Flows for the twelve months ended December 31, 2025 and 2024.

Future expected lease payments are shown below:

	As of December 31, 2025							
	PNM			**TNMP**		**TXNM Consolidated**		
		Operating					**Operating**	
	Financing	**Energy Storage**	**Other**	**Financing**	**Operating**	**Financing**	**Energy Storage**	**Other**
	(In thousands)							
2026	$ 6,319	$ 6,700	$ 7,045	$ 7,318	$ 16	$ 14,049	$ 6,700	$ 7,130
2027	5,182	$ 6,700	$ 7,049	5,439	15	10,999	$ 6,700	7,134
2028	3,748	$ 6,700	$ 7,052	4,310	11	8,253	$ 6,700	7,135
2029	2,159	$ 6,700	$ 7,039	2,754	—	4,955	$ 6,700	7,114
2030	862	$ 6,700	$ 164	815	—	1,678	$ 6,700	241
Later years	801	94,720	3,497	202	—	1,003	94,720	3,771
Total minimum lease payments	19,071	128,220	31,846	20,838	42	40,937	128,220	32,525
Less: Imputed interest	1,567	51,634	3,273	1,778	3	3,408	51,634	3,407
Lease liabilities	$ 17,504	$ 76,586	$ 28,573	$ 19,060	$ 39	$ 37,529	$ 76,586	$ 29,118

The above table includes $16.1 million, $16.9 million, and $33.2 million for PNM, TNMP, and TXNM at December 31, 2025 for expected future payments on fleet vehicle and equipment leases that could be avoided if the leased assets were returned and the lessor is able to recover estimated market value for the equipment from third parties.

At December 31, 2025, the Company has an ESA that has been executed with a lease component that has not yet commenced. The lease component begins in 2029, expires in 2044, and will be recognized as a lease asset and liability upon the commencement. The expected total fixed consideration to be paid for this arrangement, which includes non-lease payments, is approximately $94.3 million over the 20-year terms of the agreements.

(9) Fair Value of Derivative and Other Financial Instruments

Fair value is defined as the price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. Fair value is based on current market quotes as available and is supplemented by modeling techniques and assumptions made by the Company to the extent quoted market prices or volatilities are not available. External pricing input availability varies based on commodity location, market liquidity, and term of the agreement. Valuations of derivative assets and liabilities take into account nonperformance risk, including the effect of counterparties' and the Company's credit risk. The Company regularly assesses the validity and availability of pricing data for its derivative transactions. Although the Company uses its best judgment in estimating the fair value of these instruments, there are inherent limitations in any estimation technique.

Energy Related Derivative Contracts

Overview

The primary objective for the use of commodity derivative instruments, including energy contracts, options, swaps, and futures, is to manage price risk associated with forecasted purchases of energy and fuel used to generate electricity, as well as managing anticipated generation capacity in excess of forecasted demand from existing customers. PNM's energy related derivative contracts manage commodity risk. PNM is required to meet the demand and energy needs of its customers. PNM is exposed to market risk for the needs of its customers not covered under the FPPAC.

PNM's operations are managed primarily through a net asset-backed strategy, whereby PNM's aggregate net open forward contract position is covered by its forecasted excess generation capabilities or market purchases. PNM could be exposed to market risk if its generation capabilities were to be disrupted or if its load requirements were to be greater than anticipated. If all or a portion of load requirements were required to be covered as a result of such unexpected situations, commitments would have to be met through market purchases. TNMP does not enter into energy related derivative contracts.

Commodity Risk

Marketing and procurement of energy often involve market risks associated with managing energy commodities and establishing positions in the energy markets, primarily on a short-term basis. PNM routinely enters into various derivative instruments such as forward contracts, option agreements, and price basis swap agreements to economically hedge price and volume risk on power commitments and fuel requirements and to minimize the effect of market fluctuations. PNM monitors the market risk of its commodity contracts in accordance with approved risk and credit policies.

Accounting for Derivatives

Under derivative accounting and related rules for energy contracts, PNM accounts for its various instruments for the purchase and sale of energy, which meet the definition of a derivative, based on PNM's intent. During the years ended December 31, 2025, 2024, and 2023, PNM was not hedging its exposure to the variability in future cash flows from commodity derivatives through designated cash flow hedges. The derivative contracts recorded at fair value that do not qualify or are not designated for cash flow hedge accounting are classified as economic hedges. Economic hedges are defined as derivative instruments, including long-term power agreements, used to economically hedge generation assets, purchased power and fuel costs, and customer load requirements. Changes in the fair value of economic hedges are reflected in results of operations and are classified between operating revenues and cost of energy according to the intent of the hedge. PNM also uses such instruments under an NMPRC approved hedging plan to manage fuel and purchased power costs related to customers covered by its FPPAC. Changes in the fair value of instruments covered by its FPPAC are recorded as regulatory assets and liabilities. PNM has no trading transactions.

Commodity Derivatives

In November 2024, February 2025, and April 2025, PNM entered into agreements to purchase a total of 250 MW from July 1, 2025 through August 31, 2025 in order to ensure that customer demand during the 2025 summer peak load period was met. In 2024, PNM had existing agreements to purchase a total of 150 MW from July 1, 2024 through July 31, 2024 and 100 MW from August 1, 2024 through August 30, 2024. All of these agreements are related to customers covered by the FPPAC and are reflected in the commodity derivative table for each of the periods presented below.

PNM's commodity derivative instruments that are recorded at fair value, all of which are accounted for as economic hedges and considered Level 2 fair value measurements, are presented in the following line items on the Consolidated Balance Sheets:

	Economic Hedges	
	December 31,	
	2025	2024
	(In thousands)	
Other current assets	$ —	$ —
Other current liabilities	—	(5,737)
Net	$ —	$ (5,737)

Certain of PNM's commodity derivative instruments in the above table are subject to master netting agreements whereby assets and liabilities could be offset in the settlement process. PNM does not offset fair value and cash collateral for derivative instruments under master netting arrangements and the above table reflects the gross amounts of fair value assets and liabilities for commodity derivatives.

At December 31, 2025 and 2024, PNM had no amounts recognized for the legal right to reclaim cash collateral. However, amounts posted as cash collateral under margin arrangements were zero at December 31, 2025, and $0.1 million at December 31, 2024. These amounts are included in other current assets on the Consolidated Balance Sheets. At both December 31, 2025 and December 31, 2024, there were no obligations to return cash collateral.

At December 31, 2025 and 2024, PNM had no commodity derivative instruments, considered economic hedges, that did not pertain to the NMPRC-approved hedging plan discussed above. Changes in fair value had no impact on PNM's net earnings during the years ended December 31, 2025 and 2024. Commodity contract volume positions are presented in MMBTU for gas related contracts and in MWh for power related contracts.
The table below presents PNM's net buy (sell) volume positions:

	Economic Hedges	
	MMBTU	MWh
December 31, 2025	—	—
December 31, 2024	—	89,900

PNM has contingent requirements to provide collateral under commodity contracts having an objectively determinable collateral provision that are in net liability positions and are not fully collateralized with cash. In connection with managing its commodity risks, PNM enters into master agreements with certain counterparties. If PNM is in a net liability position under an agreement, some agreements provide that the counterparties can request collateral if PNM's credit rating is downgraded; other agreements provide that the counterparty may request collateral to provide it with "adequate assurance" that PNM will perform; and others have no provision for collateral.

The table below presents information about PNM's contingent requirement to provide collateral under certain commodity contracts having an objectively determinable collateral position, that are in net liability positions, and that are not fully collateralized with cash. Contractual liability represents those commodity derivative contracts recorded at fair value on the balance sheet, determined on an individual contract basis without offsetting amounts for individual contracts that are in an asset position and could be offset under master netting agreements with the same counterparty. Cash collateral posted under these contracts does not reflect letters of credit under the Company's revolving credit facilities that may have been issued as collateral. Net exposure is the net contractual liability for all contracts, including those designated as normal purchase and normal sale, offset by existing collateral and by any offsets available under master netting agreements, including both assets and liability positions.

Contingent Feature - Credit Rating	Contractual Liability	Existing Cash Collateral	Net Exposure
		(In thousands)	
December 31, 2025	$ —	$ —	$ —
December 31, 2024	$ 5,737	$ —	$ 5,737

Non-Derivative Financial Instruments

The carrying amounts reflected on the Consolidated Balance Sheets approximate fair value for cash, receivables, and payables due to the short period of maturity. Investment securities are carried at fair value. Investment securities consist of PNM assets held in the NDT for its share of decommissioning costs of PVNGS, a trust for PNM's share of decommissioning costs at SJGS, and trusts for PNM's share of final reclamation costs related to the coal mines serving SJGS and Four Corners. See Note 16. At December 31, 2025 and 2024, the fair value of investment securities included $426.4 million and $384.6 million for the NDT, $6.0 million and $8.2 million for the SJGS decommissioning trust, and $73.2 million and $82.7 million for the coal mine reclamation trusts.

PNM records a realized loss as an impairment for any available-for-sale debt security that has a fair value that is less than its carrying value. As a result, the Company has no available-for-sale debt securities for which carrying value exceeds fair value and there are no impairments considered to be "other than temporary" that are included in AOCI and not recognized in earnings. All gains and losses resulting from sales and changes in the fair value of equity securities are recognized immediately in earnings.
Gains and losses recognized on the Consolidated Statements of Earnings related to investment securities in the NDT and reclamation trusts are presented in the following table:

	Year ended December 31,		
	2025	2024	2023
		(In thousands)	
Equity securities:			
Net gains (losses) from equity securities sold	$ 38,186	$ 28,283	$ 1,086
Net gains (losses) from equity securities still held	(3,455)	(10,071)	14,152
Total net gains (losses) on equity securities	34,731	18,212	15,238
Available-for-sale debt securities:			
Net gains (losses) on debt securities	19	8,639	4,008
Net gains (losses) on investment securities	$ 34,750	$ 26,851	$ 19,246

The proceeds and gross realized gains and losses on the disposition of securities held in the NDT and coal mine reclamation trusts are shown in the following table. Realized gains and losses are determined by specific identification of costs of securities sold. Gross realized losses shown below exclude the (increase)/decrease in realized impairment losses of zero, $17.8 million, and $19.1 million for the years ended December 31, 2025, 2024 and 2023.

	Year Ended December 31, 2025	2024	2023
		(In thousands)	
Proceeds from sales	$ 693,278	$ 707,338	$ 574,199
Gross realized gains	$ 45,218	$ 35,918	$ 18,618
Gross realized (losses)	$ (7,032)	$ (16,814)	$ (32,649)

At December 31, 2025, the available-for-sale debt securities held by PNM had the following final maturities:

	Fair Value
	thousands)
Within 1 year	$ 26,931
After 1 year through 5 years	9,419
	$ 36,350

Fair Value Disclosures

The Company determines the fair values of its derivative and other financial instruments based on the hierarchy, which requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. There are three levels of inputs that may be used to measure fair value. Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly.

For investment securities, Level 2 fair values are provided by fund managers utilizing a pricing service. For Level 2 fair values, the pricing provider predominantly uses the market approach using bid side market values based upon a hierarchy of information for specific securities or securities with similar characteristics. Fair values of Level 2 investments in mutual funds are equal to net asset value (“NAV”). For commodity derivatives, Level 2 fair values are determined based on market observable inputs, which are validated using multiple broker quotes, including forward price, volatility, and interest rate curves to establish expectations of future prices. Credit valuation adjustments are made for estimated credit losses based on the overall exposure to each counterparty. For the Company’s long-term debt, Level 2 fair values are provided by an external pricing service. The pricing service primarily utilizes quoted prices for similar debt in active markets when determining fair value. Management of the Company independently verifies the information provided by pricing services. Uncategorized investments include collective investment trusts, real estate funds, and multi-strategy hedge funds, which are measured at NAV at the end of each reporting period. Audited financial statements are received for each fund and reviewed by the Company annually. Fair value for these collective investment trusts is measured using a practical expedient provided under GAAP that allows the NAV per share to be used as fair value for investments in certain entities that do not have readily determinable fair values and are considered to be investment companies. Investments valued using this practical expedient are not required to be presented within the GAAP fair value hierarchy.

Items recorded at fair value by PNM on the Consolidated Balance Sheets are presented below by level of the fair value hierarchy along with gross unrealized gains on investments in available-for-sale debt securities.

		GAAP Fair Value Hierarchy		
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Unrealized Gains
		(In thousands)		
December 31, 2025				
Cash and cash equivalents	$ 33,469	$ 33,469	$ —	
Equity securities:				
Corporate stocks, common	154,790	154,790	—	

Mutual funds and other	202,995	202,995	—	
Available-for-sale debt securities:				
U.S. government	30,619	30,619	—	$ 227
Corporate and other	5,731	—	5,731	102
Investments categorized within the fair value hierarchy	$ 427,604	$ 421,873	$ 5,731	$ 329
Uncategorized investments:				
Collective investment trusts	45,144			
Real estate funds	20,307			
Hedge funds	12,600			
Total investment securities	$ 505,655			

December 31, 2024				
Cash and cash equivalents	$ 150,745	$ 150,745	$ —	
Equity securities:				
Corporate stocks, common	134,553	134,553	—	
Mutual funds and other	135,779	135,779	—	
Available-for-sale debt securities:				
U.S. government	25,148	25,148	—	$ 202
Corporate and other	7,196	—	7,196	122
Investments categorized within the fair value hierarchy	$ 453,421	$ 446,225	$ 7,196	$ 324
Uncategorized investments:				
Collective investment trusts	22,103			
Total investment securities	$ 475,524			

The carrying amounts and fair values of long-term debt, all of which are considered Level 2 fair value measurements and are not recorded at fair value on the Consolidated Balance Sheets are presented below:

December 31, 2025	**Carrying Amount**	**Fair Value**
	(In thousands)	
TXNM	$ 5,418,564	$ 5,506,722
PNM	$ 2,861,897	$ 2,757,316
TNMP	$ 1,672,267	$ 1,662,457
December 31, 2024		
TXNM	$ 4,923,368	$ 4,706,076
PNM	$ 2,459,592	$ 2,284,362
TNMP	$ 1,464,079	$ 1,324,194

The carrying amount and fair value of the Company’s other investments presented on the Consolidated Balance Sheets are not material and not shown in the above table.

Investments Held by Employee Benefit Plans

As discussed in Note 11, PNM and TNMP have trusts that hold investment assets for their pension and other postretirement benefit plans. The fair value of the assets held by the trusts impacts the determination of the funded status of each plan, but the assets are not reflected on the Company’s Consolidated Balance Sheets. Both the PNM Pension Plan and the TNMP Pension Plan hold units of participation in the PNM Resources, Inc. Master Trust (the “PNMR Master Trust”), which was established for the investment of assets of the pension plans. The PNM and TNMP Pension Plans’ investment allocation targets in 2025 consist of 35% equities, 25% alternative investments (both of which are considered return generating), and 40% fixed income.

GAAP provides a practical expedient that allows the net asset value per share to be used as fair value for investments in certain entities that do not have readily determinable fair values and are considered to be investment companies. Fair values for alternative investments held by the PNMR Master Trust and PNM OPEB

Plan are valued using this practical expedient. Investments for which fair value is measured using that practical expedient are not required to be categorized within the fair value hierarchy. Level 2 fair values are provided by fund managers utilizing a pricing service. For level 2 fair values, the pricing provider predominately uses the market approach using bid side market value based upon a hierarchy of information for specific securities or securities with similar characteristics. Fair values of Level 2 investments in mutual funds are equal to net asset value as of year-end. Fair value prices for Level 2 corporate term loans predominately use the market approach which uses bid side market values based upon hierarchy information for specific securities or securities with similar characteristics. Alternative investments include private equity funds, hedge funds, real estate funds, and a private collective investment trust. The private equity funds are not voluntarily redeemable. These investments are realized through periodic distributions occurring over a 10 to 15 years term after the initial investment. The real estate funds and hedge funds may be voluntarily redeemed but are subject to redemption provisions that may result in the funds not being redeemable in the near term. The private collective investment trust is a non-unitized fund that does not publish daily prices. Audited financial statements are received for each fund and are reviewed by the Company annually.

The valuation of alternative investments requires significant judgment by the pricing provider due to the absence of quoted market values, changes in market conditions, and the long-term nature of the assets. The significant unobservable inputs include estimates of liquidation value, current operating performance, and future expectations of performance.

The fair values of investments held by the employee benefit plans are as follows:

		GAAP Fair Value Hierarchy	
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)
December 31, 2025		(In thousands)	
PNM Pension Plan			
Participation in PNMR Master Trust Investments:			
Investments categorized within fair value hierarchy	$ 245,141	$ 85,676	$ 159,465
Uncategorized investments	49,404		
Total Master Trust Investments	$ 294,545		
TNMP Pension Plan			
Participation in PNMR Master Trust Investments:			
Investments categorized within fair value hierarchy	$ 31,265	$ 9,278	$ 21,987
Uncategorized investments	6,404		
Total Master Trust Investments	$ 37,669		

PNM OPEB Plan						
Cash and cash equivalents	$	556	$	556	$	—
Equity securities:						
Mutual funds		40,424		40,424		—
Investments categorized within fair value hierarchy	$	40,980	$	40,980	$	—
Uncategorized investments						
Venture capital and partnership funds		35,722				
	$	76,702				
TNMP OPEB Plan						
Cash and cash equivalents	$	27	$	27	$	—
Equity securities:						
Mutual funds		6,705		6,705		—
Investments categorized within fair value hierarchy	$	6,732	$	6,732	$	—
Uncategorized investments						
Venture capital and partnership funds		657				
	$	7,389				

		GAAP Fair Value Hierarchy	
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)
December 31, 2024		(In thousands)	
PNM Pension Plan			
Participation in PNMR Master Trust Investments:			
Investments categorized within fair value hierarchy	$ 319,528	$ 106,220	$ 213,308
Uncategorized investments	59,546		
Total Master Trust Investments	$ 379,074		
TNMP Pension Plan			
Participation in PNMR Master Trust Investments:			
Investments categorized within fair value hierarchy	$ 33,294	$ 7,543	$ 25,751
Uncategorized investments	4,872		
Total Master Trust Investments	$ 38,166		
PNM OPEB Plan			
Cash and cash equivalents	$ 825	$ 825	$ —
Equity securities:			
Mutual funds	38,713	38,713	—
Investments categorized within fair value hierarchy	$ 39,538	$ 39,538	$ —
Uncategorized investments:			
Venture capital and partnership funds	31,176		
Total Master Trust Investments	$ 70,714		
TNMP OPEB Plan			
Cash and cash equivalents	$ 111	$ 111	$ —
Equity securities:			
Mutual funds	6,987	6,987	—
Investments categorized within fair value hierarchy	$ 7,098	$ 7,098	$ —
Uncategorized investments:			
Venture capital and partnership funds	484		
	$ 7,582		

The fair values of investments in the PNMR Master Trust are as follows:

	Total	GAAP Fair Value Hierarchy: Quoted Prices in Active Markets for Identical Assets (Level 1)	GAAP Fair Value Hierarchy: Significant Other Observable Inputs (Level 2)
		(In thousands)	
December 31, 2025			
PNMR Master Trust			
Cash and cash equivalents	$ 733	$ 733	$ —
Equity securities:			
Corporate stocks, common	25,946	25,946	—
Mutual funds and other	128,786	48,165	80,621
Fixed income securities:			
U.S. government	42,481	20,110	22,371
International government	4,664	—	4,664
Municipals	3,356	—	3,356
Corporate and other	70,440	—	70,440
Total investments categorized within fair value hierarchy	276,406	$ 94,954	$ 181,452
Uncategorized investments:			
Private equity funds	1,321		
Hedge funds	27,277		
Real estate funds	27,210		
	$ 332,214		
December 31, 2024			
PNMR Master Trust			
Cash and cash equivalents	$ 10,981	$ 10,981	$ —
Equity securities:			
Corporate stocks, common	34,418	34,418	—
Mutual funds and other	146,858	45,333	101,525
Fixed income securities:			
U.S. government	56,303	23,031	33,272
International government	—	—	—
Municipals	4,718	—	4,718
Corporate and other	99,544	—	99,544
Total investments categorized within fair value hierarchy	352,822	$ 113,763	$ 239,059
Uncategorized investments:			
Private equity funds	2,846		
Hedge funds	34,126		
Real estate funds	27,446		
	$ 417,240		

(10) Variable Interest Entities

How an enterprise evaluates and accounts for its involvement with variable interest entities, focuses primarily on whether the enterprise has the power to direct the activities that most significantly impact the economic performance of a variable interest entity ("VIE"). This evaluation requires continual reassessment of the primary beneficiary of a VIE.

Valencia

PNM has a PPA to purchase all of the electric capacity and energy from Valencia, a 155 MW natural gas-fired power plant near Belen, New Mexico, through May 2028. In May 2025, the NMPRC approved a new PPA for 167 MW, through 2039, in connection with the 2028 Resource Application. A third party built, owns, and operates the facility while PNM is the sole purchaser of the electricity generated. PNM is obligated to pay fixed operation and maintenance and capacity charges in addition to variable operation and maintenance charges under this PPA. For the years ended December 31, 2025, 2024, and 2023, PNM paid $20.1 million, $20.5 million, and $20.3 million for fixed charges and $3.9 million, $2.4 million, and $5.2 million for variable charges. PNM does not have any other financial obligations related to Valencia. The assets of Valencia can only be used to satisfy its obligations and creditors of Valencia do not have any recourse against PNM's assets. During the term of the PPA, PNM has the option, under certain conditions, to purchase and own up to 50% of the plant or the VIE. The PPA specifies that the purchase price would be the greater of 50% of book value reduced by related indebtedness or 50% of fair market value.

PNM sources fuel for the plant, controls when the facility operates through its dispatch, and receives the entire output of the plant, which factors directly and significantly impact the economic performance of Valencia. Therefore, PNM has concluded that the third-party entity that owns Valencia is a VIE and that PNM is the primary beneficiary of the entity since PNM has the power to direct the activities that most significantly impact the economic performance of Valencia and will absorb the majority of the variability in the cash flows of the plant. As the primary beneficiary, PNM consolidates Valencia in its financial statements. Accordingly, the assets, liabilities, operating expenses, and cash flows of Valencia are included in the Consolidated Financial Statements of PNM although PNM has no legal ownership interest or voting control of the VIE. The assets and liabilities of Valencia are set forth below and are not shown separately on the Consolidated Balance Sheets. The owner's equity and net income of Valencia are considered attributable to non-controlling interest.

Summarized financial information for Valencia is as follows:

Results of Operations

	Year Ended December 31		
	2025	2024	2023
		(In thousands)	
Operating revenues	$ 24,048	$ 22,763	$ 25,421
Operating expenses	6,112	6,723	6,896
Other Misc (Income)/Expense	—	—	(8)
Earnings attributable to non-controlling interest	$ 17,936	$ 16,040	$ 18,533

Financial Position

	December 31,	
	2025	2024
	(In thousands)	
Current assets	$ 3,205	$ 3,095
Net property, plant and equipment	41,570	44,411
Total assets	44,775	47,506
Current liabilities	787	606
Owners' equity – non-controlling interest	$ 43,988	$ 46,900

Westmoreland San Juan Mining, LLC

As discussed in the subheading Coal Supply in Note 16, PNM and Westmoreland San Juan Mining, LLC ("WSJ LLC"), a subsidiary of Westmoreland Mining Holdings, LLC have an agreement under which mine reclamation services for SJGS will be provided.

TXNM has $19.3 million in letters of credit to facilitate the issuance of reclamation bonds. The letters of credit support results in TXNM having a variable interest in WSJ LLC since TXNM is subject to possible loss in the event performance by TXNM is required under the letters of credit support. TXNM considers the possibility of loss under the letters of credit support to be remote since the purpose of posting the bonds is to provide assurance that WSJ LLC performs the required reclamation of the mine site in accordance with applicable regulations and the reclamation services agreement provides WSJ LLC the ability to recover the cost of reclamation. As discussed in Note 16, each of the SJGS participants has established and actively fund trusts to meet future reclamation obligations.

WSJ LLC is considered a VIE. TXNM's analysis of its arrangements with WSJ LLC concluded that WSJ LLC has the ability to direct its reclamation services, which are the factors that most significantly impact the economic performance of WSJ LLC. Other than PNM being able to monitor reclamation activities, the reclamation services were solely under the control of WSJ LLC, including developing reclamation plans, hiring of personnel, and incurring operating and maintenance expenses. Neither TXNM nor PNM has any ability to direct or influence the reclamation activities. PNM's involvement through the reclamation services agreement is a protective right rather than a participating right and WSJ LLC still has the power to direct the activities that most significantly impact the economic performance of WSJ LLC. If WSJ LLC performs reclamation services more efficiently than anticipated, its economic performance will improve. Conversely, if WSJ LLC does not perform reclamation services as efficiently as anticipated, its economic performance will be negatively impacted. Accordingly, TXNM believes WSJ LLC is the primary beneficiary and, therefore, WSJ LLC is not consolidated by either TXNM or PNM. The amounts outstanding under the letters of credit support continue to be TXNM's maximum exposure to loss from the VIE at December 31, 2025.

ETBC I

ETBC I is a wholly-owned, special purpose subsidiary of PNM that was formed in August 2023 for the limited purpose of purchasing, owning, and administering energy transition property, issuing securitized bonds, and performing related activities authorized by the NMPRC. On November 15, 2023, ETBC I issued the ETBC I Securitized Bonds and used the proceeds to purchase energy transition property from PNM. The energy transition property purchased includes the right to impose, bill, collect, and adjust a non-bypassable energy transition charge from all PNM retail customers until the ETBC I Securitized Bonds are paid in full and all allowed financing costs have been recovered. The ETBC I Securitized Bonds are secured by the energy transition property and cash collections from the Energy Transition Charges are the sole source of funds to satisfy the debt obligation. The bondholders have no recourse to PNM.

PNM acts as the servicer of the energy transition property on behalf of ETBC I and is responsible for metering, calculating, billing, and collecting the Energy Transition Charges. On behalf of ETBC I, PNM is required to remit all collections of the Energy Transition Charges to the trustee for the ETBC I Securitized Bonds. PNM has the power to direct the activities that most significantly impact the economic performance of ETBC I and will absorb the majority of the variability in the cash flows of the entity. As the primary beneficiary, PNM consolidates ETBC I in its financial statements. Accordingly, the assets, liabilities, operating expenses, and cash flows of ETBC I are included in the Consolidated Financial Statements of PNM. The following tables summarize the impact of ETBC I on PNM's Consolidated Financial Statements:

	Results of Operations	
	Year ended December 31,	
	2025	2024
	(In thousands)	
Electric Operating Revenues	$ 27,010	$ 24,798
Depreciation and amortization	6,945	4,550
Interest Charges	19,738	20,073
Other	327	175
Net Earnings	$ —	$ —

Financial Position

	December 31,	
	2025	2024
	(In thousands)	
Regulatory assets - Current	$ —	$ —
Restricted cash (included in Other current assets)	11,954	15,838
Restricted cash (included in Other deferred charges)	1,743	1,748
Securitized Cost (included in Regulatory assets - Deferred)	329,134	336,079
Current installments of long-term debt	7,303	6,907
Accrued interest and taxes	7,306	7,452
Regulatory liabilities - Current	3,009	6,975
Long-term Debt	324,531	331,726

(11) Pension and Other Postretirement Benefits

TXNM and its subsidiaries maintain qualified defined benefit pension plans, postretirement benefit plans providing medical and dental benefits, and executive retirement programs (collectively, the “PNM Plans” and “TNMP Plans”). TXNM maintains the legal obligation for the benefits owed to participants under these plans. The periodic costs or income of the PNM Plans and TNMP Plans are included in regulated rates to the extent attributable to regulated operations. PNM and TNMP receive a regulated return on the amounts funded for pension and OPEB plans in excess of the periodic cost or income to the extent included in retail rates (a “prepaid pension asset”).

Participants in the PNM Plans include eligible employees and retirees of TXNM and PNM. Participants in the TNMP Plans include eligible employees and retirees of TNMP. The PNM pension plan was frozen at the end of 1997 with regard to new participants, salary levels, and benefits. Through December 31, 2007, additional credited service could be accrued under the PNM pension plan up to a limit determined by age and service. The TNMP pension plan was frozen at December 31, 2005, with regard to new participants, salary levels, and benefits.

A plan sponsor is required to (a) recognize in its statement of financial position an asset for a plan’s overfunded status or a liability for a plan’s underfunded status; (b) measure a plan’s assets and its obligations that determine its funded status as of the end of the employer’s fiscal year; and (c) recognize changes in the funded status of a defined benefit postretirement plan in the year in which the changes occur.

Unrecognized prior service costs and unrecognized gains or losses are required to be recorded in AOCI and subsequently amortized. To the extent the amortization of these items will ultimately be recovered or returned through future rates, PNM and TNMP record the costs as a regulatory asset or regulatory liability. The amortization of these incurred costs is included as pension and postretirement benefit periodic cost or income in subsequent years.

The Company maintains trust funds for the pension and OPEB plans from which benefits are paid to eligible employees and retirees. The Company’s funding policy is to make contributions to the trusts, as determined by an independent actuary, that comply with minimum guidelines of the Employee Retirement Income Security Act and the IRC. Information concerning the fair value of investments is contained in Note 9. The Company has in place a policy that defines the investment objectives, establishes performance goals of asset managers, and provides procedures for the manner in which investments are to be reviewed.

The plans implement investment strategies to achieve the following objectives:

- Implement investment strategies commensurate with the risk that the Corporate Investment Committee deems appropriate to meet the obligations of the pension plans and OPEB plans, minimize the volatility of expense, and account for contingencies
- Transition asset mix over the long-term to a higher proportion of high-quality fixed income investments as the plans’ funded statuses improve

Management is responsible for the determination of the asset target mix and the expected rate of return. The target asset allocations are determined based on consultations with external investment advisors. The expected long-term rate of return on pension and postretirement plan assets is calculated on the market-related value of assets. Actual gains and losses on pension and OPEB plan assets are recognized in the market-related value of assets equally over a period of not more than five years, which reduces year-to-year volatility. For the PNM Plans and TNMP Plans, the market-related value of assets is equal to the prior year's market-related value of assets adjusted for contributions, benefit payments and investment gains and losses that are within a corridor of plus or minus 4.0% around the expected return on market value. Gains and losses that are outside the corridor are amortized over five years.

In December 2025, TXNM, in its capacity as sponsor of the qualified benefit pension plans, entered into a commitment agreement with Delaware Life Insurance Company (the "Insurer") under which the plans agreed to purchase a nonparticipating single premium group annuity contract that will transfer to the Insurer 62% of the defined benefit pension obligations and associated plan assets related to pension benefits associated with a previously disposed of gas distribution business. The contract covers approximately 1,400 retirees from the previously disposed of business. To the extent provided in the contract, the Insurer has made an irrevocable commitment, and will be solely responsible, to pay benefits of each Participant that are due on and after June 1, 2026. The transaction will result in no changes to the amount of benefits payable to Participants. As a result of the transaction, PNM recognized a one-time settlement charge of $58.8 million related to the immediate recognition of unamortized net actuarial loss associated with the portion of the pension involved in the transaction.

Pension Plans

For defined benefit pension plans, including the executive retirement plans, the PBO represents the actuarial present value of all benefits attributed by the pension benefit formula to employee service rendered prior to that date using assumptions regarding future compensation levels. The ABO represents the PBO without considering future compensation levels. Since the pension plans are frozen, the PBO and ABO are equal.

The following table presents information about the PBO, fair value of plan assets, and funded status of the plans:

	PNM		TNMP	
	Year Ended December 31,		Year Ended December 31,	
	2025	2024	2025	2024
	(In thousands)			
PBO at beginning of year	$ 393,361	$ 418,657	$ 39,223	$ 42,582
Service cost	—	—	—	—
Interest cost	21,539	21,709	2,145	2,214
Actuarial (gain) loss	10,160	(6,063)	852	(2,047)
Benefits paid	(39,864)	(40,942)	(5,313)	(3,526)
Settlements	(91,938)	—	—	—
PBO at end of year	293,258	393,361	36,907	39,223
Fair value of plan assets at beginning of year	379,154	407,211	38,225	41,353
Actual return on plan assets	46,156	12,884	4,735	247
Employer contributions	—	1	—	151
Benefits paid	(39,864)	(40,942)	(5,312)	(3,526)
Settlements	(91,938)	—	—	—
Fair value of plan assets at end of year	293,508	379,154	37,648	38,225
Funded status – asset (liability) for pension benefits	$ 250	$ (14,207)	$ 741	$ (998)

Actuarial (gain) loss results from changes in:

	PNM		TNMP	
	Year Ended December 31,		Year Ended December 31,	
	2025	2024	2025	2024
	(in thousands)			
Discount rates	$ 8,726	$ (9,376)	$ 577	$ (961)
Demographic experience	1,434	3,313	275	(1,125)
Mortality rate	—	—	—	—
Other assumptions and experience	—	—	—	39
	$ 10,160	$ (6,063)	$ 852	$ (2,047)

The following table presents pre-tax information about net actuarial (gain) loss in AOCI as of December 31, 2025.

	PNM	TNMP
	(In thousands)	
Amounts in AOCI not yet recognized in net periodic benefit cost at beginning of year	$ 102,513	$ —
Experience (gain) loss	(6,163)	(952)
Regulatory asset (liability) adjustment	3,559	952
Amortization recognized in net periodic benefit (income)	(5,415)	—
Pension settlement charge	$ (58,768)	$ —
Amounts in AOCI not yet recognized in net periodic benefit cost at end of year	$ 35,726	$ —

The following table presents the components of net periodic benefit cost (income):

	Year Ended December 31,		
	2025	2024	2023
	(In thousands)		
PNM			
Service cost	$ —	$ —	$ —
Interest cost	21,539	21,709	23,653
Expected return on plan assets	(29,833)	(31,029)	(29,196)
Amortization of net loss	12,494	10,646	10,583
Amortization of prior service cost	—	—	—
Pension Settlement Charge	$ 58,768	$ —	$ —
Net periodic benefit cost	$ 62,968	$ 1,326	$ 5,040
TNMP			
Service cost	$ —	$ —	$ —
Interest cost	2,145	2,214	2,402
Expected return on plan assets	(2,933)	(2,749)	(2,697)
Amortization of net loss	672	556	439
Amortization of prior service cost	—	—	—
Settlement loss	—	—	—
Net periodic benefit cost	$ (116)	$ 21	$ 144

The following significant weighted-average assumptions were used to determine the PBO and net periodic benefit cost (income). Should actual experience differ from actuarial assumptions, the PBO and net periodic benefit cost (income) would be affected.

	Year Ended December 31,		
PNM	**2025**	**2024**	**2023**
Discount rate for determining December 31 PBO	5.49 %	5.78 %	5.46 %
Discount rate for determining net periodic benefit cost	5.78	5.46	5.74
Expected return on plan assets	7.29	6.86	6.30
Rate of compensation increase	N/A	N/A	N/A
TNMP			
Discount rate for determining December 31 PBO	5.53 %	5.78 %	5.47 %
Discount rate for determining net periodic benefit cost	5.78	5.47	5.75
Expected return on plan assets	7.00	5.95	5.50
Rate of compensation increase	N/A	N/A	N/A

The assumed discount rate for determining the PBO was determined based on a review of long-term high-grade bonds and management’s expectations. The expected long-term rate of return on plan assets reflects the average rate of earnings expected on the funds invested, or to be invested, to provide for the benefits included in the PBO. Factors that are considered include, but are not limited to, historic returns on plan assets, current market information on long-term returns (e.g., long-term bond rates) and current and target asset allocations between asset categories. If all other factors were to remain unchanged, a 1% decrease in the expected long-term rate of return would cause PNM’s and TNMP’s 2026 net periodic benefit cost to increase $2.9 million and $0.4 million (analogous changes would result from a 1% increase). The actual rate of return for the PNM and TNMP pension plans was 12.97% and 13.31% for the year ended December 31, 2025.

The Company’s long-term pension investment strategy is to invest in assets whose interest rate sensitivity is correlated with the pension liability. The Company uses an investment strategy, known as Liability Driven Investing, that increases the liability matching investments as the funded status of the pension plans improve. The Company’s investment allocation targets consist of 35% equities, 25% alternative investments (both of which are considered return generating), and 40% liability matching securities that are primarily bonds and other fixed income investments. Equity investments are primarily in domestic securities that include large-, mid-, and small-capitalization companies. The pension plans have a 13% targeted allocation to equities of companies domiciled primarily in developed countries outside of the U.S. The equity investments category includes active and passive managed domestic equity securities that are benchmarked against a variety of style indices. Fixed income investments are primarily corporate bonds of companies from diversified industries and government securities. Alternative investments include investments in hedge funds, real estate funds, and private equity funds. The private equity funds are structured as multi-manager multi-strategy fund of funds to achieve a diversified position in these asset classes. The hedge funds use multi-strategies that pursue various absolute return strategies such as relative value, merger arbitrage, event driven equities, and structured credit. The real estate investments are commingled real estate portfolios that invest in a diversified portfolio of assets including commercial property, infrastructure, storage facilities and multi-family housing. See Note 9 for fair value information concerning assets held by the pension plans.

The following pension benefit payments are expected to be paid:

	PNM	TNMP
	(In thousands)	
2026	$ 29,416	$ 4,228
2027	28,934	4,031
2028	28,186	3,937
2029	27,479	3,772
2030	26,491	3,570
2031 - 2035	118,524	14,461

Based on current law, funding requirements, and estimates of portfolio performance, the Company does not expect to make any cash contribution to the pension plans from 2026 through 2030. The funding assumptions were developed using a discount rate of 5.5%. Actual amounts to be funded in the future will be dependent on the actuarial assumptions at that time, including the appropriate discount rates. PNM and TNMP may make additional contributions at their discretion.

Other Postretirement Benefit Plans

For postretirement benefit plans, the APBO is the actuarial present value of all future benefits attributed under the terms of the postretirement benefit plan to employee service rendered to date. The following table presents information about the APBO, the fair value of plan assets, and the funded status of the plans:

	PNM		TNMP	
	Year Ended December 31,		Year Ended December 31,	
	2025	2024	2025	2024
	(In thousands)			
APBO at beginning of year	$ 41,601	$ 46,217	$ 6,754	$ 7,331
Service cost	—	—	18	21
Interest cost	2,267	2,387	373	385
Participant contributions	1,274	1,463	339	357
Actuarial (gain)	2,460	(2,205)	55	(147)
Benefits paid	(6,115)	(6,261)	(1,079)	(1,193)
Curtailment loss	—	—	—	—
Plan design changes	—	—	183	—
APBO at end of year	41,487	41,601	6,643	6,754
Fair value of plan assets at beginning of year	72,003	73,392	7,542	8,353
Actual return on plan assets	7,832	3,216	711	25
Employer contributions	933	193	—	—
Participant contributions	1,274	1,463	339	357
Benefits paid	(6,114)	(6,261)	(1,080)	(1,193)
Fair value of plan assets at end of year	75,928	72,003	7,512	7,542
Funded status – asset	$ 34,441	$ 30,402	$ 869	$ 788

As of December 31, 2025, the fair value of plan assets exceeds the APBO for both PNM's and TNMP's OPEB Plans, and the resulting net asset is presented in other deferred charges on the Consolidated Balance Sheets.

Actuarial (gain) loss results from changes in:

	PNM		TNMP	
	Year Ended December 31,		Year Ended December 31,	
	2025	2024	2025	2024
	(in thousands)			
Discount rates	$ 822	$ (877)	$ 161	$ (179)
Claims, contributions, and demographic experience	1,638	(1,425)	(106)	32
Assumed participation rate	—	97	—	—
Mortality rate	—	—	—	—
Dental trend assumption	—	—	—	—
	$ 2,460	$ (2,205)	$ 55	$ (147)

In the year ended December 31, 2025, actuarial losses of $0.2 million were recorded as adjustments to regulatory assets for the PNM OPEB plan. For the TNMP OPEB plan, actuarial gains of $0.2 million were recorded as adjustments to regulatory liabilities.

The following table presents the components of net periodic benefit cost (income):

	Year Ended December 31,		
	2025	2024	2023
		(In thousands)	
PNM			
Service cost	$ —	$ —	$ —
Interest cost	2,267	2,387	2,703
Expected return on plan assets	(5,536)	(5,563)	(4,969)
Amortization of net loss	—	—	—
Curtailment loss	—	—	—
Net periodic benefit (income)	$ (3,269)	$ (3,176)	$ (2,266)
TNMP			
Service cost	$ 18	$ 21	$ 21
Interest cost	373	385	425
Expected return on plan assets	(481)	(515)	(481)
Amortization of net (gain)	(496)	(642)	(760)
Net periodic benefit (income)	$ (586)	$ (751)	$ (795)

The following significant weighted-average assumptions were used to determine the APBO and net periodic benefit cost. Should actual experience differ from actuarial assumptions, the APBO and net periodic benefit cost would be affected.

	Year Ended December 31,		
PNM	2025	2024	2023
Discount rate for determining December 31 APBO	5.49 %	5.78 %	5.48 %
Discount rate for determining net periodic benefit cost	5.78	5.48	5.75
Expected return on plan assets	6.95	6.60	5.90
Rate of compensation increase	N/A	N/A	N/A
TNMP			
Discount rate for determining December 31 APBO	5.49 %	5.78 %	5.48 %
Discount rate for determining net periodic benefit cost	5.78	5.48	5.75
Expected return on plan assets	5.55	5.25	4.70
Rate of compensation increase	N/A	N/A	N/A

The assumed discount rate for determining the APBO was determined based on a review of long-term high-grade bonds and management's expectations. The expected long-term rate of return on plan assets reflects the average rate of earnings expected on the funds invested, or to be invested, to provide for the benefits included in the APBO. Factors that are considered include, but are not limited to, historic returns on plan assets, current market information on long-term returns (e.g., long-term bond rates), and current and target asset allocations between asset categories. If all other factors were to remain unchanged, a 1% decrease in the expected long-term rate of return would cause PNM's and TNMP's 2026 net periodic benefit cost to increase $0.8 million and $0.1 million (analogous changes would result from a 1% increase). The actual rate of return for the PNM and TNMP OPEB plans was 11.2% and 9.9% for the year ended December 31, 2025.

The following table shows the assumed health care cost trend rates for the PNM OPEB plan:

	PNM	
	December 31,	
	2025	2024
Health care cost trend rate assumed for next year	6.50 %	6.50 %
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	4.75	4.75
Year that the rate reaches the ultimate trend rate	2033	2033

TNMP's exposure to cost increases in the OPEB plan is minimized by a provision that limits TNMP's share of costs under the plan. Costs of the plan in excess of the limit, which was reached at the end of 2001, are wholly borne by the participants. As a result, a one-percentage-point change in assumed health care cost trend rates would have no effect on either the net periodic expense or the year-end APBO. Effective January 1, 2018, the PNM OPEB plan was amended to limit the annual increase in the Company's costs to 5%. Increases in excess of the limit are born by the PNM OPEB plan participants.

The Company's OPEB plans invest in a portfolio that is diversified by asset class and style strategies. The OPEB plans generally use the same pension fixed income and equity investment managers and utilize the same overall investment strategy as described above for the pension plans, except there is no allocation to alternative investments. The OPEB plans have a target asset allocation of 30% equities and 70% fixed income. See Note 9 for fair value information concerning assets held by the other postretirement benefit plans. The following OPEB payments, which reflect expected future service and are net of participant contributions, are expected to be paid:

	PNM	TNMP
	(In thousands)	
2026	$ 4,728	$ 606
2027	4,519	596
2028	4,312	590
2029	4,007	576
2030	3,782	548
2031 - 2035	16,362	2,493

PNM and TNMP did not make cash contributions to the OPEB trusts in 2025 and less than $0.1 million and $0.2 million in 2024. PNM and TNMP do not expect to make cash contributions to the OPEB trusts in 2026-2030. However, a portion of the disbursements attributable to the OPEB trust are paid by PNM and are therefore considered to be contributions to the PNM OPEB plan. Payments by PNM on behalf of the PNM OPEB plan are expected to be $3.2 million in 2026 and $11.2 million in 2027-2030.

Executive Retirement Programs

TNMP has terminated its Executive Retirement Program as there are no longer any participants. For the executive retirement programs, the following table presents information about the PBO and funded status of the plans:

	PNM		TNMP	
	Year Ended December 31,		Year Ended December 31,	
	2025	2024	2025	2024
	(In thousands)			
PBO at beginning of year	$ 9,031	$ 9,714	$ —	$ 316
Service cost	—	—	—	—
Interest cost	487	496	—	15
Actuarial (gain) loss	(371)	(47)	—	(314)
Benefits paid	(1,118)	(1,132)	—	(17)
PBO at end of year – funded status	8,029	9,031	—	—
Less current liability	1,043	1,171	—	—
Non-current liability	$ 6,986	$ 7,860	$ —	$ —

The following table presents pre-tax information about net actuarial loss in AOCI as of December 31, 2025.

	December 31, 2025	
	PNM	TNMP
	(In thousands)	
Amount in AOCI not yet recognized in net periodic benefit cost at beginning of year	$ 1,001	$ —
Experience (gain)	(371)	—
Regulatory asset adjustment	215	—
Amortization recognized in net periodic benefit (income)	(79)	—
Amount in AOCI not yet recognized in net periodic benefit cost at end of year	$ 766	$ —

The following table presents the components of net periodic benefit cost:

	Year Ended December 31,		
	2025	2024	2023
	(In thousands)		
PNM			
Service cost	$ —	$ —	$ —
Interest cost	487	496	540
Amortization of net loss	189	200	152
Amortization of prior service cost	—	—	—
Net periodic benefit cost	$ 676	$ 696	$ 692
TNMP			
Service cost	$ —	$ —	$ —
Interest cost	—	15	18
Amortization of net loss	—	—	—
Amortization of prior service cost	—	—	—
Net periodic benefit cost	$ —	$ 15	$ 18

The following significant weighted-average assumptions were used to determine the PBO and net periodic benefit cost. Should actual experience differ from actuarial assumptions, the PBO and net periodic benefit cost would be affected.

	Year Ended December 31,		
PNM	2025	2024	2023
Discount rate for determining December 31 PBO	5.50 %	5.78 %	5.45 %
Discount rate for determining net periodic benefit cost	5.78	5.45	5.73
Long-term rate of return on plan assets	N/A	N/A	N/A
Rate of compensation increase	N/A	N/A	N/A
TNMP			
Discount rate for determining December 31 PBO	N/A	N/A	5.47 %
Discount rate for determining net periodic benefit cost	—	5.47	5.75
Long-term rate of return on plan assets	N/A	N/A	N/A
Rate of compensation increase	N/A	N/A	N/A

The assumed discount rate for determining the PBO was determined based on a review of long-term high-grade bonds and management's expectations. The impacts of changes in assumptions or experience were not significant.

Disbursements under the executive retirement program, funded by PNM and TNMP, which are considered to be contributions to the plan were $1.3 million and zero in the year ended December 31, 2025, and $1.3 million and $0.1 million for the year ended December 31, 2024.

The following executive retirement plan payments, which reflect expected future service, are expected:

	PNM	TNMP
	(In thousands)	
2026	$ 1,071	$ —
2027	1,026	—
2028	973	—
2029	914	—
2030	852	—
2031 - 2035	3,305	—

Other Retirement Plans

TXNM sponsors a 401(k) defined contribution plan for eligible employees, including those of its subsidiaries. TXNM's contributions to the 401(k) plan consist of a discretionary matching contribution equal to 75% of the first 6% of eligible compensation contributed by the employee on a before-tax basis. TXNM also makes a non-matching contribution ranging from 3% to 10% of eligible compensation based on the eligible employee's age. TXNM also provides executive deferred compensation benefits through an unfunded, non-qualified plan. The purpose of this plan is to permit certain key employees of TXNM who participate in the 401(k) defined contribution plan to defer compensation and receive credits without reference to the certain limitations on contributions.

A summary of expenses for these other retirement plans is as follows:

	Year Ended December 31,		
	2025	2024	2023
	(In thousands)		
TXNM			
401(k) plan	$ 18,220	$ 17,514	$ 16,118
Non-qualified plan	$ 4,299	$ 4,350	$ 1,197
PNM			
401(k) plan	$ 12,458	$ 11,896	$ 10,839
Non-qualified plan	$ 2,783	$ 2,937	$ 825
TNMP			
401(k) plan	$ 5,762	$ 5,617	$ 5,279
Non-qualified plan	$ 1,516	$ 1,414	$ 372

(12) Stock-Based Compensation

TXNM has various stock-based compensation programs, which provide restricted stock awards, that are performance based and time based, under the Performance Equity Plan ("PEP"). Although certain PNM and TNMP employees are eligible to participate in the TXNM plans, PNM and TNMP do not have separate employee stock-based compensation plans. Performance stock awards awarded under the PEP are awarded for a three-year, overlapping performance period. Performance stock awards with performance periods ending from 2024 through 2025 did not include market targets. Performance stock awards with performance periods ending after 2025 are subject to achieving both performance and market targets. Other awards of restricted stock are only subject to time-based vesting requirements.

Performance Equity Plan

The PEP provides for the granting of non-qualified stock options, restricted stock rights, performance shares, performance units, and stock appreciation rights to officers, key employees, and non-employee members of the Board. Restricted stock under the PEP refers to awards of stock subject to vesting, performance, or market conditions rather than to shares with contractual post-vesting restrictions. Generally, the awards vest ratably over three years from the grant date of the award. However, awards with performance or market conditions vest upon satisfaction of those conditions. In addition, plan provisions provide that upon retirement, participants become 100% vested in certain stock awards. The vesting period for awards of restricted stock to non-employee members of the Board is one year. The total number of shares of TXNM common stock subject to all awards under the 2014 PEP, as approved by TXNM's shareholders in May 2014, may not exceed 13.5 million shares, subject to adjustment and certain share counting rules set forth in the PEP. This share pool is charged five shares for each share subject to restricted stock or other full value award. In May 2023, TXNM's shareholders approved the 2023 PEP which set the maximum number of shares subject to all awards to be 2.5 million shares. The 2023 PEP share pool is charged a single share for each award.

Source of Shares

The source of shares for exercised stock options and vested restricted stock is currently shares acquired on the open market by an independent agent, rather than newly issued shares.

Accounting for Stock Awards

The stock-based compensation expense related to restricted stock awards without performance or market conditions to participants that are retirement eligible on the grant date is recognized immediately at the grant date and is not amortized. Compensation expense for other such awards is amortized to compensation expense over the shorter of the requisite vesting period or the period until the participant becomes retirement eligible. Compensation expense for performance-based shares is recognized ratably over the performance period as required service is provided and is adjusted periodically to reflect the level of achievement expected to be attained. Compensation expense related to market-based shares is recognized ratably over the measurement period, regardless of the actual level of achievement, provided the employees meet their service requirements.

Total compensation expense for stock-based payment arrangements recognized by TXNM for the years ended December 31, 2025, 2024, and 2023 was $8.8 million, $9.5 million, and $7.2 million. Stock compensation expense of $5.6 million, $5.0 million, and $4.8 million was charged to PNM and $3.2 million, $2.7 million, and $2.4 million was charged to TNMP for the years ended December 31, 2025, 2024, and 2023. At December 31, 2025, TXNM had unrecognized compensation expense related to stock awards of $6.3 million, which is expected to be recognized over an average of 1.62 years.

TXNM receives a tax deduction for the value of restricted stock at the vesting date. To the extent the tax deduction exceeds the Company's cumulative expense related to a stock award, an excess tax benefit is recorded. When the cumulative expense exceeds the tax deduction, a tax deficiency is recorded. All excess tax benefits and deficiencies are recorded to tax expense and classified as operating cash flows when used to reduce taxes payable.

	Year Ended December 31,		
Excess Tax Benefits (Deficiencies)	**2025**	**2024**	**2023**
		(In thousands)	
PNM	$ 345	$ 10	$ 185
TNMP	162	4	76
TXNM	521	17	261

TNMP used excess tax benefits to reduce income taxes payable and the benefit was reflected in cash flows from operating activities. The benefit of excess tax benefits at PNM and TXNM will be reflected in operating cash flows when they reduce income taxes payable.

The grant date fair value for restricted stock and stock awards with Company internal performance targets is determined based on the market price of TXNM common stock on the date of the agreements reduced by the present value of future dividends that will not be received prior to vesting. The grant date fair value is applied to the total number of shares that are anticipated to vest, although the number of performance shares that ultimately vest cannot be determined until after the performance periods end. The grant date fair value of stock awards with market targets is determined using Monte Carlo simulation models, which provide grant date fair values that include an expectation of the number of shares to vest at the end of the measurement period. The following table summarizes the weighted-average assumptions used to determine the awards grant date fair value:

Restricted Shares and Performance-Based Shares	Year Ended December 31, 2025	2024	2023
Expected quarterly dividends per share	$ 0.4075	$ 0.3875	$ 0.3675
Risk-free interest rate	4.00 %	4.27 %	4.46 %
Market-Based Shares [1]			
Dividend yield	3.12 %	4.21 %	N/A
Expected volatility	15.67 %	13.09 %	N/A
Risk-free interest rate	4.12 %	4.31 %	N/A

[1] Restricted stock expected to be awarded under the PEP for performance periods ending in 2023 do not have market targets.

The following table summarizes activity in restricted stock awards including performance-based and market-based shares:

	Restricted Stock Shares	Weighted-Average Grant Date Fair Value
Outstanding at December 31, 2024	241,237	$ 37.05
Granted	215,137	48.90
Released	(221,862)	43.10
Forfeited	(6,708)	37.54
Outstanding at December 31, 2025	227,804	$ 42.30

Included as granted and released in the table above are 50,923 previously awarded shares that were earned for the 2022 - 2024 performance measurement period and ratified by the Board in February 2025 (based upon achieving targets at above “target”, below “maximum” levels). Also included, as granted and released, are 1,524 of other RSAs for participants who retired and immediately vested. Included as released, are 44,577 of previously awarded shares that were earned for the 2023 - 2025 performance measurement period (based upon achieving targets at above “threshold”, below “target” levels) that the Board elected to release in December 2025. Excluded from the table above are 242,177 and 195,119 shares for the three-year performance periods ending in 2026 and 2027 that will be awarded if all performance criteria are achieved at maximum levels and all executives remain eligible.

At December 31, 2023, the Company had active retention agreements with its then Chairman and Chief Executive Officer and its then Senior Vice President and General Counsel under which they would be awarded a total of 26,766 and 8,922 respectively of restricted stock rights if they remained employed through the award’s vesting date which is the earliest of 24 months from the grant date or six months following the termination of the Avangrid Merger. As of December 31, 2023, upon the notice from Avangrid regarding the termination of the Avangrid Merger Agreement, these awards vested on June 30, 2024.

On December 4, 2023, the Company entered into a retention agreement with its then President and Chief Operating Officer under which he would receive a retention bonus of $1.0 million to be paid in increments beginning in December 2023 and continuing each December until 2025. On April 8, 2024, pursuant to the retention agreement, the Board elected to convert the unvested portion of the retention bonus of $0.8 million into restricted stock rights whereby each share of restricted stock is equal to one share of Company common stock as of the first trading day after expiration of the then current black-out period. On May 3, 2024, subsequent to the expiration of the black-out period, 19,851 restricted stock rights were awarded and 6,617 have vested as of December 31, 2024, in accordance with the original terms of the retention agreement. On December 1, 2025, the remaining 13,234 restricted stock rights vested in accordance with the original terms of the retention agreement.

On September 16, 2024, in connection with a one-time sign-on equity grant, the Company’s newly appointed General Counsel, Senior Vice President Regulatory and Public Policy, and Corporate Secretary was awarded 9,300 shares of restricted stock, of which 50% vested immediately and the remaining 50% vested on September 16, 2025.

The following table provides additional information concerning restricted stock activity, including performance-based and market-based shares:

Restricted Stock	Year Ended December 31, 2025	2024	2023
Weighted-average grant date fair value	$ 43.10	$ 38.37	$ 41.98
Total fair value of restricted shares that vested (in thousands)	$11,748	$ 8,380	$ 8,689

(13) Regulatory Assets and Liabilities

The operations of PNM and TNMP are regulated by the NMPRC, PUCT, and FERC and the provisions of GAAP for rate-regulated enterprises are applied to its regulated operations. Regulatory assets represent probable future recovery of previously incurred costs that will be collected from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process.

Regulatory assets and liabilities reflected in the Consolidated Balance Sheets are presented below.

	PNM				TNMP			
	December 31,				December 31,			
	2025		2024		2025		2024	
	(In thousands)							
Assets:								
Current:								
FPPAC	$	2,039	$	30,487	$	—	$	—
NMPRC hedging plan		—		5,737		—		—
Transmission cost recovery factor		—		—		—		5,268
Energy efficiency costs		—		—		2,583		—
Grid Modernization Plan		6,460		—		—		—
HB 5247		—		—		17,534		—
System Resiliency Plan		—		—		13,169		—
		8,499		36,224		33,286		5,268
Non-Current:								
SJGS securitized costs	$	329,134	$	336,079	$	—	$	—
SJGS ETA		27,437		24,996		—		—
SJGS - non-ETA		106,349		114,333		—		—
PVNGS leased interest		78,624		82,982		—		—
EIM		11,431		15,189		—		—
TEP		11,620		4,942		—		—
Loss on reacquired debt		11,271		12,507		22,423		23,721
Pension and OPEB		165,243		176,171		19,216		21,087
Deferred income taxes		76,880		74,925		8,258		8,570
Excess ADIT		—		—		12,955		6,542
AMS retirement and other costs		—		—		13,409		12,851
Deferred COVID-19 costs		2,094		3,328		—		—
Hurricane Beryl		—		—		20,510		20,958
Other		12,708		11,858		9,687		10,964
		832,791		857,310		106,458		104,693
Total regulatory assets	$	841,290	$	893,534	$	139,744	$	109,961
Liabilities:								
Current:								
PVNGS rate refunds	$	(3,127)	$	(19,194)	$	—	$	—
Renewable energy rider		(1,300)		(4,786)		—		—
Energy efficiency costs		(916)		(2,459)		—		(602)
Transmission cost recovery factor		—		—		(2,592)		—
SJGS securitized costs		(3,009)		(6,975)				
Other		(78)		(157)		—		—
		(8,430)		(33,571)		(2,592)		(602)
Non-Current:								
Cost of removal	$	(252,856)	$	(247,280)	$	(190,072)	$	(147,296)
Deferred income taxes		(221,469)		(253,158)		(76,757)		(80,152)
Renewable energy tax benefits		(12,170)		(13,317)		—		—
PVNGS rate refunds		—		(3,277)		—		—
Pension and OPEB		—		—		(2,084)		(2,589)
COVID-19 cost savings		—		(469)		—		—
Other		(1,911)		(1,200)		—		—
		(488,406)		(518,701)		(268,913)		(230,037)
Total regulatory liabilities	$	(496,836)	$	(552,272)	$	(271,505)	$	(230,639)

The Company's regulatory assets and regulatory liabilities are reflected in rates charged to customers or have been addressed in a regulatory proceeding. The Company does not receive or pay a rate of return on the following regulatory assets and regulatory liabilities (and their remaining amortization periods): SJGS securitized costs (over the life of the ETBC I Securitized Bonds); portions of PVNGS Leased Interest (through 2044); PVNGS rate refunds (through 2026); deferred income taxes (over the remaining life of the taxable item, up to the remaining life of utility plant); pension and OPEB costs (through 2040).

The Company is permitted, under rate regulation, to accrue and record a regulatory liability for the estimated cost of removal and salvage associated with certain of its assets through depreciation expense. Actuarial losses and prior service costs for pension plans are required to be recorded in AOCI; however, to the extent authorized for recovery through the regulatory process these amounts are recorded as regulatory assets or liabilities. Based on prior regulatory approvals, the amortization of these amounts will be included in the Company's rates. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, the Company believes that future recovery of its regulatory assets is probable..

(14) Construction Program and Jointly-Owned Electric Generating Plants

PNM is a participant in jointly-owned power plant projects. The primary operating or participation agreements for the other joint projects expire in July 2041 for Four Corners, December 2046 for Luna, and November 2047 for PVNGS. PNM's expenditures for additions to utility plant were $585.2 million in 2025, including expenditures on jointly-owned projects. TNMP does not participate in the ownership or operation of any generating plants, but incurred expenditures for additions to utility plant of $563.1 million during 2025. On a consolidated basis, TXNM's expenditures for additions to utility plant were $1,195.9 million in 2025.

Joint Projects

Under the agreements for the jointly-owned projects, PNM has an undivided interest in each asset and liability of the project and records its pro-rata share of each item in the corresponding asset and liability account on PNM's Consolidated Balance Sheets. Likewise, PNM records its pro-rata share of each item of operating and maintenance expenses for its jointly-owned plants within the corresponding operating expense account in its Consolidated Statements of Earnings. PNM is responsible for financing its share of the capital and operating costs of the joint projects.

At December 31, 2025, PNM's interests in jointly-owned generating facilities including transmission, distribution, and plant in common are:

Station (Type)	Plant in Service	Accumulated Depreciation (1)	Construction Work in Progress	Composite Interest
	(In thousands)			
PVNGS (Nuclear)	$ 828,030	$ 431,571	$ 30,781	7.29 %
Four Corners Units 4 and 5 (Coal)	$ 323,698	$ 100,554	$ 6,516	13.00 %
Luna (Gas)	$ 106,398	$ 36,881	$ 2,327	33.33 %

(1) Includes cost of removal.

Palo Verde Nuclear Generating Station

PNM is a participant in the three units of PVNGS with APS (the operating agent), SRP, EPE, SCE, SCPPA, and The Department of Water and Power of the City of Los Angeles. PNM has ownership interests of 2.3% in Unit 1, 9.4% in Unit 2, and 10.2% in Unit 3. In January 2023, leased capacity of 104 MW in PVNGS Unit 1 expired and the rights to the capacity were acquired by SRP from the lessors subsequently, making PNM's interest in PVNGS be 7.6% at December 31, 2023. In January 2024, the leased capacity of 10 MW in PVNGS Unit 2 expired and the rights were also acquired by SRP, reducing PNM's interest in PVNGS to 7.3%. See Note 8 for additional information concerning the PVNGS leases.

Four Corners Power Plant

PNM is a participant in two units of Four Corners with APS (the operating agent), an affiliate of APS, SRP, and Tucson. PNM has a 13.0% undivided interest in Units 4 and 5 of Four Corners. The Four Corners plant site is located on land within the Navajo Nation and is subject to an easement from the federal government. APS, on behalf of the Four Corners participants, negotiated amendments to an existing agreement with the Navajo Nation, which extends the owners' right to operate the plant on the site to July 2041. See Notes 16 and 17 for additional information about Four Corners.

Luna Energy Facility

Luna is a combined-cycle power plant near Deming, New Mexico. Luna is owned equally by PNM, Tucson, and Samchully Power & Utilities 1, LLC. The operation and maintenance of the facility have been contracted to North American Energy Services by PNM.

(15) Asset Retirement Obligations

AROs are recorded based on studies to estimate the amount and timing of future ARO expenditures and reflect underlying assumptions, such as discount rates, estimates of the future costs for decommissioning, and the timing of the removal activities to be performed. Approximately 76.2% of PNM's total ARO liabilities are related to nuclear decommissioning of PVNGS. PNM is responsible for all decommissioning obligations related to its entire interest in PVNGS, including portions both during and after termination of the leases. Studies of the decommissioning costs of PVNGS, SJGS, Four Corners, and other facilities are performed periodically and revisions to the ARO liabilities are recorded. Changes in the assumptions underlying the calculations may also require revisions to the estimated AROs when identified.

A reconciliation of the ARO liabilities is as follows:

	TXNM	PNM	TNMP
		(In thousands)	
Liability at December 31, 2022	$ 223,377	$ 222,549	$ 828
Liabilities incurred	—	—	—
Liabilities settled	(3,482)	(3,482)	—
Accretion expense	10,218	10,148	70
Revisions to estimated cash flows[1]	15,418	15,418	—
Liability at December 31, 2023	245,531	244,633	898
Liabilities incurred	—	—	—
Liabilities settled	(12,451)	(12,432)	(19)
Accretion expense	11,538	11,462	76
Liability at December 31, 2024	244,618	243,663	955
Liabilities incurred[2]	6,226	6,226	—
Liabilities settled	(7,769)	(7,477)	(292)
Accretion expense	12,022	11,941	81
Liability at December 31, 2025	$ 255,097	$ 254,353	$ 744

(1) Reflects an increase of $15.4 million related to an updated PVNGS decommissioning study.

(2) Reflects an increase of $3.4 million related to a new ash pond at Lordsburg station and a $2.8 million increase related to a new Four Corners study for pond and CCR decommissioning projects.

(16) Commitments and Contingencies

Merger-Related Litigation

Counsel for TXNM has received a number of demand letters from certain law firms on behalf of individuals who are purported TXNM shareholders, accompanied by draft complaints naming TXNM and its directors as defendants and alleging that TXNM's preliminary proxy statement with respect to the Merger omitted or misrepresented certain material information. Such draft complaints include a request for injunctive relief with respect to the TXNM shareholder vote to approve, and the closing of, the Merger, as well as other remedies, including counsel fees. In August 2025, reported shareholders filed complaints in New York state court alleging disclosure violations and seeking injunctive relief. TXNM believes that the allegations set forth in the demand letters, draft complaints, and complaints are without merit and will defend against such actions vigorously.

Overview

There are various claims and lawsuits pending against the Company. In addition, the Company is subject to federal, state, and local environmental laws and regulations and periodically participates in the investigation and remediation of various sites. In addition, the Company periodically enters into financial commitments in connection with its business operations. Also, the Company is involved in various legal and regulatory proceedings in the normal course of its business. See Note 17. It is not possible at this time for the Company to determine fully the effect of all litigation and other legal and regulatory proceedings on its financial position, results of operations, or cash flows.

With respect to some of the items listed below, the Company has determined that a loss is not probable or that, to the extent probable, cannot be reasonably estimated. In some cases, the Company is not able to predict with any degree of certainty the range of possible loss that could be incurred. The Company assesses legal and regulatory matters based on current information and makes judgments concerning their potential outcome, giving due consideration to the nature of the claim, the amount and nature of any damages sought, and the probability of success. Such judgments are made with the understanding that the outcome of any litigation, investigation, or other legal proceeding is inherently uncertain. The Company records liabilities for matters where it is probable a loss has been incurred, and the amount of loss is reasonably estimatable. The actual outcomes of the items listed below could ultimately differ from the judgments made and the differences could be material. The Company cannot make any assurances that the amount of reserves or potential insurance coverage will be sufficient to cover the cash obligations that might be incurred as a result of litigation or regulatory proceedings. Except as otherwise disclosed, the Company does not expect that any known lawsuits, environmental costs, or commitments will have a material effect on its financial condition, results of operations, or cash flows.

Commitments and Contingencies Related to the Environment

PVNGS Decommissioning Funding

The costs of decommissioning a nuclear power plant are substantial. PNM is responsible for all decommissioning obligations related to its entire interest in PVNGS, including portions under leases both during and after termination of the leases. PNM has a program for funding its share of decommissioning costs for PVNGS, including portions previously held under leases. The nuclear decommissioning funding program is invested in equities and fixed income instruments in qualified and non-qualified trusts. PNM funded $1.3 million for each of the years ended December 31, 2025, 2024 and 2023 into the qualified trust funds. The fair value of the trusts at December 31, 2025 and 2024 was $426.4 million and $384.6 million.

Nuclear Spent Fuel and Waste Disposal

Nuclear power plant operators are required to enter into spent fuel disposal contracts with the DOE that require the DOE to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. Although the Nuclear Waste Policy Act required the DOE to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998, the DOE announced that it would not be able to open the repository by 1998 and sought to excuse its performance of these requirements. In November 1997, the DC Circuit issued a decision preventing the DOE from excusing its own delay but refused to order the DOE to begin accepting spent nuclear fuel. Based on this decision and the DOE's delay, a number of utilities, including APS (on behalf of itself and the other PVNGS owners, including PNM), filed damages actions against the DOE in the Court of Federal Claims. The lawsuits filed by APS alleged that damages were incurred due to DOE's continuing failure to remove spent nuclear fuel and high-level waste from PVNGS. APS and the DOE entered into a settlement agreement, subsequently extended, that established a process for the payment of claims for costs incurred through December 31, 2025. Under the settlement agreement, APS must submit claims annually for payment of allowable costs. APS is currently evaluating a proposed extension of the settlement agreement to cover costs paid through December 31, 2028. PNM records estimated claims on a quarterly basis. The benefit from the claims is passed through to customers under the FPPAC.

PNM estimates that it will incur approximately $55.6 million (in 2023 dollars) for its share of the costs related to the on-site interim storage of spent nuclear fuel at PVNGS for the remaining term of the operating licenses. PNM accrues these costs as a component of fuel expense as the nuclear fuel is consumed. At December 31, 2025 and 2024, PNM had a liability for interim storage costs of $15.5 million and $13.4 million, which is included in other deferred credits.

PVNGS has sufficient capacity at its on-site Independent Spent Fuel Storage Installation ("ISFSI") to store all of the nuclear fuel that will be irradiated during the initial operating license period, which ends in December 2027. Additionally, PVNGS has sufficient capacity at its on-site ISFSI to store a portion of the fuel that will be irradiated during the period of extended operation, which ends in November 2047. If uncertainties regarding the U.S. Government's obligation to accept and store spent fuel are not favorably resolved, APS will evaluate alternative storage solutions that may obviate the need to expand the ISFSI to accommodate all of the fuel that will be irradiated during the period of extended operation.

The New Mexico Energy Transition Act

The New Mexico Energy Transition Act ("ETA") sets a statewide standard that requires investor-owned electric utilities to have specified percentages of their electric-generating portfolios be from renewable and zero-carbon generating resources. The passage of the ETA amended the REA to require utilities operating in New Mexico to have renewable portfolios equal to 40% by 2025, 50% by 2030, 80% by 2040, and 100% zero-carbon energy by 2045. The amendments also allow for the recovery of undepreciated investments and decommissioning costs related to qualifying EGUs that the NMPRC has required be removed from retail jurisdictional rates, provided replacement resources to be included in retail rates have lower or zero-carbon emissions. The ETA requires the NMPRC to review and approve utilities' annual renewable portfolio plans to ensure compliance with the RPS. Also pursuant to the ETA, the NM Environmental Improvement Board adopted standards of performance that limit CO_2 emissions to no more than 1,100 lbs. per MWh beginning January 1, 2023, for new and existing coal-fired EGUs with original installed capacities exceeding 300 MW.

The ETA provides for a transition from fossil-fuel generation resources to renewable and other carbon-free resources through certain provisions relating to the abandonment of coal-fired generating facilities. These provisions include the use of energy transition bonds to finance certain costs of abandoning coal-fired facilities that are retired prior to January 1, 2023, for facilities operated by a "qualifying utility," or prior to January 1, 2032 for facilities that are not operated by a qualifying utility. The amount of energy transition bonds that can be issued to recover abandonment costs is limited to the lesser of $375.0 million or 150% of the undepreciated investment of the facility as of the abandonment date. Proceeds provided by energy transition bonds must be used only for purposes related to providing utility service to customers and to pay energy transition costs (as defined by the ETA). These costs may include plant decommissioning and coal mine reclamation costs provided those costs have not previously been recovered from customers or disallowed by the NMPRC or by a court order. Proceeds from energy transition bonds may also be used to fund severances for employees of the retired facility and related coal mine and to promote economic development, education and job training in areas impacted by the retirement of the coal-fired facilities. Energy transition bonds must be issued under a NMPRC-approved financing order, are secured by "energy transition property," are non-recourse to the issuing utility, and are repaid by a non-bypassable charge paid by all customers of the issuing utility. These customer charges are subject to an adjustment mechanism designed to provide for timely and complete payment of principal and interest due under the energy transition bonds.

The ETA also provides that utilities must obtain NMPRC approval of competitively procured replacement resources that shall be evaluated based on their cost, economic development opportunity, ability to provide jobs with comparable pay and benefits to those lost upon retirement of the facility, and that do not exceed emissions thresholds specified in the ETA. In determining whether to approve replacement resources, the NMPRC must give preference to resources with the least environmental impacts, those with higher ratios of capital costs to fuel costs, and those located in the school district of the abandoned facility. The ETA also provides for the procurement of energy storage facilities and gives utilities discretion to maintain, control, and operate these systems to ensure reliable and efficient service.

The ETA has had and will have a significant impact on PNM's future generation portfolio, including PNM's retirement of SJGS in 2022. PNM cannot predict the full impact of the ETA with respect to Four Corners or the outcome of its future generating resource abandonment and replacement resource filings with the NMPRC. See additional discussion in Note 17 of PNM's SJGS and Four Corners Abandonment Applications.

The Clean Air Act

Regional Haze

Pursuant to the CAA, states are required to establish goals for improving visibility in national parks and wilderness areas (also known as Class I areas) and to develop long-term strategies for reducing emissions of air pollutants that cause visibility impairment in their own states and for preventing degradation in other states. States must establish a series of interim goals to ensure continued progress by adopting a new SIP every ten years. In the first SIP planning period, states were required to conduct BART determinations for certain covered facilities, including utility boilers, built between 1962 and 1977 that have the potential to emit more than 250 tons per year of visibility impairing pollution. For all future SIP planning periods, states must evaluate whether additional emissions reduction measures may be needed to continue making reasonable progress toward natural visibility conditions.

SIPs for the second planning period were due in July 2021, which deadline NMED was unable to meet. NMED is currently preparing its SIP for the second compliance period and has notified PNM that it will not be required to submit a regional haze four-factor analysis for SJGS since PNM retired its share of SJGS in 2022. On August 30, 2022, EPA published in the Federal Register an official "Finding of Failure to Submit" for states, including New Mexico, that have not yet submitted a round 2 regional haze SIP. This action by EPA started a two-year clock for it to issue a FIP which deadline has now passed. NMED petitioned the NM Environmental Improvement Board to adopt a proposed SIP and submitted a final revised plan to the NM Environmental Improvement Board on March 3, 2025. PNM submitted comments on the proposed SIP in response to a request for comments by NMED. The NM Environmental Improvement Board held a public hearing from April 28 to April 30, 2025. On December 8, 2025, the NM Environmental Improvement Board adopted the proposed SIP and final rule. No PNM generating stations were identified as reasonable progress units under the adopted SIP indicating that no additional emissions reductions measures may be necessary at this time.

On March 12, 2025, as part of EPA's list of 31 deregulatory actions, EPA announced it would restructure the Regional Haze Program. On October 2, 2025, EPA published an advanced notice of proposed rulemaking to solicit information from the public to help develop regulatory changes on the implementation and structure of the Regional Haze Rule ("RHR"). The advanced notice itself does not impose any requirements but requests input on how EPA can revise the RHR to streamline regulatory requirements impacting states' visibility improvement obligations. Comments were due December 1, 2025.

Carbon Dioxide Emissions

In 2015, EPA established standards to limit CO_2 emissions from power plants, including (1) Carbon Pollution Standards for new, modified, and reconstructed power plants; and (2) the Clean Power Plan for existing power plants. Challengers successfully petitioned the U.S. Supreme Court for a stay of the Clean Power Plan. In 2019, EPA repealed the Clean Power Plan, promulgated the ACE Rule, and revised the implementing regulations for all emission guidelines. The ACE Rule was also challenged, and on January 19, 2021, the DC Circuit issued an opinion in American Lung Association and American Public Health Association v. EPA, et al., vacating the ACE Rule.

Numerous parties sought review by the U.S. Supreme Court, and on June 30, 2022, the U.S. Supreme Court held that the "generation shifting" approach in the Clean Power Plan exceeded the powers granted to EPA by Congress. Of broader significance in administrative law, the Court's opinion expressly invoked the "major question" doctrine, which requires rules involving issues of "vast economic or political significance" to be supported by clear statutory authorization. In cases where there is no clear statement of authority, courts need not defer to the agency's statutory interpretation on "major questions." The decision sets legal precedent for future rulemakings by EPA and other federal regulatory agencies whereby the agencies' authority may be limited based upon similar reasoning.

The litigation over the Carbon Pollution Standards remains held in abeyance but could be reactivated by the parties upon a determination by the court that reconsideration of the rule has concluded.

In 2024, EPA adopted regulatory actions under CAA Sections 111(b) and (d) to replace the Clean Power Plan and the ACE Rule. The final rules include revised new source performance standards under Section 111(b) for all new natural gas-fired combustion turbines and emission guidelines under Section 111(d) requiring states to develop standards of performance for GHG emissions from existing fossil-fuel-fired electric steam generating units. In the final rules, EPA determined that the standards for existing coal- or gas-fired steam generating units must be based on the use of either CCS (long-term), natural gas co-firing (medium-term), or exempt from the rule via early retirement. The standards for new combustion turbines must be based on CCS (base load), efficient simple cycle design (intermediate load), or lower-emitting fuels (low load). Over a dozen states, several industry groups and some power companies and labor unions filed challenges to the rule at the DC Circuit, which heard oral arguments on December 6, 2024. However, President Trump issued several executive orders on January 20, 2025, directing his Administration to review all agency actions and suspend, revise, or rescind those identified as imposing an undue burden on domestic energy resources. On March 12, 2025, as part of EPA's reconsideration of 31 environmental regulations, EPA announced the agency will reconsider the previous Administration's regulations on GHG standards and guidelines for power plants. On June 17, 2025, EPA published a proposed rule in the Federal Register with two alternatives to repeal or revise the GHG emission standards for EGUs. EPA primarily proposes to find that GHG emissions from fossil fuel-fired power plants "do not contribute significantly to dangerous air pollution" under the meaning of CAA Section 111, which would preclude EPA from regulating GHG emissions from those plants. As a result, EPA is proposing to repeal all GHG standards for the power sector promulgated under CAA Section 111 in both 2015 and 2024. EPA also proposed, in the alternative, to find that CCS is not adequately demonstrated and that neither CCS nor gas co-firing are the best system of emission reduction for GHG emissions from power plants, which findings also support repeal of those specific requirements from the rules adopted in 2024. Comments were due by September 15, 2025, and EPA had indicated it intended to finalize the proposed rule in the first quarter of 2026.

Because the CAA 111 rule does not contain provisions for existing natural gas units, on March 26, 2024, EPA announced it was opening a non-regulatory docket and issued framing questions to gather input about ways to design a stronger, more durable approach to GHG regulation of existing gas combustion turbines. The docket was open for public comment from March 26, 2024 to May 28, 2024 and the agency held a policy forum to bring stakeholders together to share ideas with EPA and others. Under the Trump Administration, EPA is unlikely to propose a rule based on this non-regulatory docket.

In 2021, President Biden signed an extensive executive order aimed at addressing climate change concerns domestically and internationally. The order was intended to build on the initial climate-related actions the Biden Administration took on January 20, 2021. It addressed a wide range of issues, including establishing climate change concerns as an essential element of U.S. foreign and security policy, identifying a process to determine the U.S. INDC under the Paris Agreement, and establishing a Special Presidential Envoy for Climate that would sit on the National Security Council. On April 22, 2021, at the Earth Day Summit, as part of the U.S.'s re-entry into the Paris Agreement, President Biden unveiled the goal to cut U.S. emissions by 50% - 52% from 2005 levels by 2030, nearly double the GHG emissions reduction target set by the Obama Administration. The 2030 goal joined President Biden's other climate goals which included a carbon pollution-free power sector by 2035 and a net-zero emissions economy by no later than 2050. In an executive order issued on January 20, 2025, President Trump ordered his Administration to withdraw the U. S. from the Paris Agreement and from any agreement, pact, accord, or similar commitment made under the United Nations Framework Convention on Climate Change.

On August 1, 2025, EPA published a proposal to rescind the 2009 final rule commonly known as the Endangerment Finding. In the Endangerment Finding, EPA found that current and projected atmospheric concentrations of the well-mixed combination of six GHGs threaten public health and welfare, and that the combined emissions of these GHGs from new motor vehicles and engines contribute to the GHG pollution that threatens public health and welfare. This provided the basis for EPA's subsequent GHG regulations applicable to stationary sources. Comments were due September 15, 2025. On January 7, 2026, EPA sent the proposed rule rescinding the 2009 Endangerment Finding to OMB. On February 12, 2026, the final rule was finalized as proposed, repealing all GHG emission standards for certain vehicles and engines promulgated on the basis of the Endangerment Finding. While the Endangerment Finding did not directly impose any requirements on EGUs, EPA cited the Endangerment Finding as a basis for its authority to regulate GHG emissions from EGUs under CAA Section 111.

PNM's review of the GHG emission reductions standards that have or may occur as a result of legislation or regulation is ongoing. We are currently determining what impact, if any, the final rules will have on our business, results of operations, and financial condition.

National Ambient Air Quality Standards ("NAAQS")

The CAA requires EPA to set NAAQS for pollutants reasonably anticipated to endanger public health or welfare. EPA has set NAAQS for certain pollutants, including NOx, SO_2, ozone, and particulate matter.

NO_X Standard – In 2018, EPA published the final rule to retain the current primary health-based NOx standards of which NO_2 is the constituent of greatest concern and is the indicator for the primary NAAQS. EPA concluded that the current 1-hour and annual primary NO_2 standards are requisite to protect public health with an adequate margin of safety. The rule became effective on May 18, 2018. The State of New Mexico has attained the current NOx NAAQS standards.

SO_2 Standard – In 2019, EPA announced its final decision to retain, without changes, the primary health-based NAAQS for SO_2. Specifically, EPA retained the current 1-hour standard for SO_2, which is 75 parts per billion, based on the 3-year average of the 99th percentile of daily maximum 1-hour SO_2 concentrations. In 2021, EPA published in the Federal Register the initial air quality designations for all remaining areas not yet designated under the 2010 SO_2 Primary NAAQS. All areas of New Mexico have been designated attainment/unclassifiable through four rounds of designations by EPA.

Ozone Standard – In 2015, EPA finalized the new ozone NAAQS and lowered both the primary and secondary 8-hour standard from 75 to 70 parts per billion. With ozone standards becoming more stringent, fossil-fueled generation units will come under increasing pressure to reduce emissions of NOx and volatile organic compounds since these are the pollutants that form ground-level ozone. During 2017 and 2018, EPA released rules establishing area designations for ozone. In those rules, San Juan County, New Mexico, where Four Corners is located, is designated as attainment/unclassifiable and only a small area in Doña Ana County, New Mexico is designated as marginal non-attainment. Although Afton Generating Station is located in Doña Ana County, it is not located within the small area designated as non-attainment for the 2015 ozone standard. PNM does not believe there will be material impacts to its facilities because of the non-attainment designation of the small area within Doña Ana County. Until EPA approves attainment designations for the Navajo Nation and releases a proposal to implement the revised ozone NAAQS, PNM is unable to predict what impact the adoption of these standards may have on Four Corners. On July 13, 2020, EPA proposed to retain the existing ozone NAAQS based on a review of the full body of currently available scientific evidence and exposure/risk information, but on August 21, 2023, EPA announced an entirely new review of the ozone standard. PNM cannot predict the outcome of this matter.

In 2019, EPA issued findings that several states, including New Mexico, had failed to submit interstate transport SIPs for the 2015 8-hour ozone NAAQS, triggering an obligation for EPA to issue a FIP within two years. In response, NMED submitted a Good Neighbor SIP on July 27, 2021, that demonstrates that there are no significant contributions from New Mexico to downwind problems in meeting the federal ozone standard. On March 15, 2023, EPA Administrator Regan signed a final action imposing a FIP on multiple states but did not include a FIP for New Mexico because the most updated modeling available at the time of the proposal confirmed the state did not contribute to downwind ozone nonattainment or maintenance areas. However, the updated modeling EPA used in the final rule indicated that New Mexico may be significantly contributing to one or more non-attainment or maintenance areas. In light of that modeling result, on February 16, 2024, the EPA published a proposed rule partially disapproving the SIPs for New Mexico and four other states (Arizona, Iowa, Kansas, and Tennessee) and expanding the Good Neighbor FIP to apply to these states. The FIP aspect of the proposed rule would have required fossil fuel-fired power plants in these five states to participate in an allowance-based ozone season NOx emissions trading program beginning in 2025, but the outgoing Biden Administration did not finalize the rule. On March 10, 2025, in the DC Circuit, the EPA filed a motion for voluntary remand of its ozone interstate transport FIP for the 2015 ozone NAAQS to reconsider the rule and had anticipated completing a new rulemaking by Fall 2026. In addition, EPA has now reconsidered the policies underlying its Good Neighbor rule, and, on January 30, 2026, EPA issued a proposed rule to approve New Mexico's SIP submission because it will not contribute significantly to nonattainment or interfere with maintenance of the 2015 8-hour ozone NAAQS in any other state. If finalized, the EPA will withdraw the prior proposed partial SIP disapproval.

PM Standard – In 2023, EPA published, in the Federal Register, a proposal to lower the annual fine PM standard to between 9-10 µg/m3 but retain the rest of its PM standards, including the current daily fine PM standard, the daily coarse PM standard, and the secondary PM standards. The final rule was published on March 6, 2024, lowering the primary annual PM 2.5 NAAQS to 9 ug/m3, and became effective May 6, 2024. States will have until March 2032 to attain compliance with the new standard. During the multi-year implementation process, EPA will designate attainment/nonattainment areas by March 6, 2026, and states will submit a SIP to EPA by September 6, 2027. This implementation process also applies to the Albuquerque-Bernalillo County Environmental Health Department who may combine efforts with NMED. However, even before any designations are made, the new standard is effective for conducting required modeling for permit applications and revisions. The lower standard is expected to result in new nonattainment areas throughout the country and could prompt additional PM control requirements, but PNM cannot predict the impacts of the outcome of future rulemaking. The PM standard was challenged in the D.C. Circuit, and, following the change in administration, EPA filed a motion for voluntary vacatur of the rule, which remains pending. Although initial designations were due in February 2026, EPA is expected to seek an extension of that deadline by one year to allow time for the court to rule on the motion for voluntary vacatur.

Cooling Water Intake Structures

In 2014, EPA issued a rule establishing national standards for certain cooling water intake structures at existing power plants and other facilities under the Clean Water Act to protect fish and other aquatic organisms by minimizing impingement mortality (the capture of aquatic wildlife on intake structures or against screens) and entrainment mortality (the capture of fish or shellfish in water flow entering and passing through intake structures).

To minimize impingement mortality, the rule provides operators of facilities, such as Four Corners, seven options for meeting Best Technology Available ("BTA") standards for reducing impingement. The permitting authority must establish the BTA for entrainment on a site-specific basis, taking into consideration an array of factors, including endangered species and social costs and benefits. Affected sources must submit source water baseline characterization data to the permitting authority to assist in the BTA determination. Compliance deadlines under the rule are tied to permit renewals, including any subject to a schedule of compliance established by the permitting authority in the permit itself.

In 2018, several environmental groups sued EPA Region IX in the U.S. Court of Appeals for the Ninth Circuit over EPA's failure to timely reissue the Four Corners NPDES permit. The petitioners asked the court to issue a *writ of mandamus* compelling EPA Region IX to take final action on the pending NPDES permit by a reasonable date. EPA subsequently reissued the NPDES permit. The permit did not contain conditions related to the cooling water intake structure rule, because EPA determined that the facility had achieved BTA for both impingement and entrainment by operating a closed-cycle recirculation system. Several environmental groups filed a petition for review with EPA's Environmental Appeals Board ("EAB") concerning the reissued permit. The environmental groups alleged that the permit was reissued in contravention of the Clean Water Act and did not contain limits or conditions required by EPA's ELG applicable to Four Corners or EPA's cooling water intake structures rule, among others. EPA withdrew the Four Corners NPDES permit in order to examine the issues raised by the environmental groups and then issued an updated NPDES permit in 2019. The permit was once again appealed to the EAB and was stayed before the effective date, but the EAB issued an order denying the petition for review on September 30, 2020. Thereafter, the Regional Administrator of the EPA signed a notice of final permit decision, and the NPDES permit was issued on November 9, 2020. The permit became effective December 1, 2020. On January 22, 2021, the environmental groups filed a petition for review of the EAB's decision with the U.S. Court of Appeals for the Ninth Circuit. The September 2019 permit remained in effect pending the outcome of this appeal. On March 21, 2022, EPA provided notice in the Federal Register of a proposed settlement agreement with the environmental groups. The parties subsequently executed the settlement agreement as of May 2, 2022. Under the settlement, the lawsuit was administratively closed through September 6, 2023, during which time a third-party consultant spent 12 months sampling discharges from Four Corners and EPA spent three months completing an analysis. On December 1, 2023, EPA issued a modification, effective December 31, 2023, to the NPDES permit that had been issued on November 9, 2020. The modification applies to permit elements related to effluent discharge. PNM cannot predict whether the analysis required to be performed by EPA under the settlement agreement will result in further changes to the NPDES permit but does not anticipate that it will have a material impact on PNM's financial position, results of operations, or cash flows.

Effluent Limitation Guidelines

In 2013, EPA published proposed revised wastewater ELG establishing technology-based wastewater discharge limitations for fossil fuel-fired electric power plants. EPA signed the final Steam Electric ELG rule in 2015. The final rule, which became effective on January 4, 2016, phased in the new, more stringent requirements in the form of effluent limits for arsenic, mercury, selenium, and nitrogen for wastewater discharged from wet scrubber systems and zero discharge of pollutants in ash transport water that must be incorporated into plants' NPDES permits. The 2015 rule required each plant to comply between 2018 and 2023 depending on when it needed a new or revised NPDES permit.

The Steam Electric ELG rule was challenged in the U.S. Court of Appeals for the Fifth Circuit by numerous parties. In 2017, EPA signed a notice indicating its intent to reconsider portions of the rule, and the Fifth Circuit issued an order severing the issues under reconsideration and holding the case in abeyance as to those issues. However, the court allowed challenges to other portions of the rule to proceed. In 2019, the Fifth Circuit granted those challenges and issued an opinion vacating several portions of the rule, specifically those related to legacy wastewater and leachate, for which the court deemed the standards selected by EPA to be arbitrary and capricious.

In 2017, EPA published a final rule for postponement of certain compliance dates. The rule postponed the earliest date on which compliance with the ELG for regulated waste streams would be required from November 1, 2018 until November 1, 2020. In 2019, EPA published a proposed rule revising the original ELG while maintaining the compliance dates. In 2020, EPA published in the Federal Register the final Steam Electric ELG and Standards for the Steam Electric Power Generating Point Source Category, revising the final 2015 guidelines for both flue gas desulfurization wastewater and bottom ash transport water. The 2020 rule required compliance with new limits as soon as possible on or after October 13, 2021, but no later than December 31, 2025.

In 2021, EPA published notice that it would undertake a supplemental rulemaking to revise the ELG after completing its review of the rules reconsidered in 2020. As part of this process, EPA committed to determine whether more stringent limitations and standards would be appropriate. On March 29, 2023, EPA published the proposed ELG Rule in the Federal Register. The proposed rule included stricter limitations for wastewater discharges for coal-fired facilities but allowed for flexibilities for those coal-powered facilities that would decommission or repower by December 31, 2028, to December 31, 2032.

On May 9, 2024, EPA published a final rule to further revise the ELG. This final supplemental rule updated the technology-based limitations applicable to flue gas desulfurization wastewater, bottom ash transport water, and legacy wastewater at existing sources, as well as combustion residual leachate at new and existing sources. The 2024 rule was challenged in the U.S. Court of Appeals for the Eighth Circuit, but the court denied motions for a stay, so the rule remains in effect. On March 12, 2025, EPA announced it would reconsider the ELGs for the steam electric power generating industry. On October 2, 2025, EPA published proposed and direct final rules for extension of deadlines and other provisions. Comments were due November 3, 2025. On November 28, 2025, EPA withdrew the direct final rule due to adverse comments and on December 31, 2025, published a final rule revising various deadlines and other provisions in the 2024 rule.

Reeves Station discharges cooling tower blowdown to a publicly owned treatment plant and no longer holds an NPDES permit; therefore, it is expected that no ELG requirements will be imposed.

See "Cooling Water Intake Structures" above for additional discussion of Four Corners' current NPDES permit. Four Corners may be required to change equipment and operating practices affecting boilers and ash handling systems, as well as change its waste disposal techniques during the next NPDES permit renewal. PNM is unable to predict the outcome of these matters or a range of the potential costs of compliance.

Santa Fe Generating Station

PNM and NMED are parties to agreements under which PNM has installed a remediation system to treat water from a City of Santa Fe municipal supply well and an extraction well to address gasoline contamination in the groundwater at the site of PNM's former Santa Fe Generating Station and service center. A 2008 NMED site inspection report states that neither the source nor extent of contamination at the site has been determined and that the source may not be the former Santa Fe Generating Station. During 2013 and 2014, PNM and NMED collected additional samples that showed elevated concentrations of nitrate and volatile organic compounds in some of the monitoring wells at the site. In addition, one monitoring well contained free-phase hydrocarbon products. PNM collected a sample of the product for "fingerprint" analysis. The results of this analysis indicated the product was a mixture of older and newer fuels. The presence of newer fuels in the sample suggests the hydrocarbon product likely originated from off-site sources. In 2015, PNM and NMED entered into a memorandum of understanding to address changing groundwater conditions at the site under which PNM agreed to continue hydrocarbon investigation under the supervision of NMED. Qualified costs are eligible for payment through the New Mexico Corrective Action Fund ("CAF"), which is administered by the NMED Petroleum Storage Tank Bureau. In 2019, PNM received notice from NMED that an abatement plan for the site is required to address concentrations of previously identified compounds, unrelated to those discussed above, found in the groundwater. NMED approved PNM's abatement plan proposal, which covers field work and reporting.

Field work related to the investigation under both the CAF and abatement plan requirements was completed and activities and findings associated with the field work were presented in two separate reports and released to stakeholders in early 2020. Subsequent field work was completed in July 2020, and two reports were released supporting PNM's contention that off-site sources have impacted, and are continuing to impact, the local groundwater in the vicinity of the former Santa Fe Generating Station.

In 2021, NMED approved both the field work plans required for site characterization and associated work activities which were completed by the end of 2022 and a report was submitted to NMED in 2023. Groundwater sampling for the abatement plan's first semiannual work was completed in 2023, and the associated report was completed and submitted to NMED. In addition, the work plan for the 2023 CAF work was completed and submitted to NMED in July 2023. NMED approved this work plan in December 2023. The activities from the work plan include the installation of three monitoring wells which were completed in December 2024. A report summarizing the well installation is under preparation. Site wide sampling was completed in March 2025, with reports provided to NMED. In November 2025 additional groundwater sampling was initiated and completed in December 2025. A report summarizing the groundwater sampling results is under preparation.

The City of Santa Fe has stopped operating its well at the site, which is needed for PNM's groundwater remediation system to operate. As a result, PNM has stopped performing remediation activities at the site. However, PNM's monitoring and other abatement activities at the site are ongoing and will continue until the groundwater meets applicable federal and state standards or until NMED determines that remediation is not required, whichever is earlier. PNM is also in communications with the City of Santa Fe to determine when operations at the site might resume. PNM is not able to assess the duration of this project or estimate the impact on its obligations if PNM is required to resume groundwater remediation activities at the site. PNM is unable to predict the outcome of these matters.

Coal Combustion Residuals Waste Disposal

CCRs consisting of fly ash, bottom ash, and gypsum generated from coal combustion and emission control equipment at SJGS have been disposed of in the surface mine pits adjacent to the plant. SJGS does not operate any onsite CCR impoundments or landfills. The NMMMD currently regulates mine reclamation activities at the San Juan mine, including placement of CCRs in the surface mine pits, with federal oversight by the OSM. APS disposes of CCRs in onsite ponds and dry storage areas at Four Corners. Ash management at Four Corners is regulated by EPA and the New Mexico State Engineer's Office.

EPA's 2015 coal ash rule included a non-hazardous waste determination for coal ash and sets minimum criteria for existing and new CCR landfills and surface impoundments. In 2016, the Water Infrastructure Improvements for the Nation Act (the "WIIN Act") was signed into law to address critical water infrastructure needs in the U.S. and contained a number of provisions related to CCRs. Among other things, the WIIN Act allowed, but did not require, states to develop and submit CCR permit programs for EPA approval, provided flexibility for states to incorporate EPA's 2015 rule for CCRs or develop other criteria that are at least as protective as EPA's rule, and required EPA to approve state permit programs within 180 days of submission by the state. Because states are not required to implement their own CCR permit programs, EPA was required to develop a federal permit program in states that chose not to implement a program, subject to congressional funding. Until state or federal permit programs are in effect, the 2015 rule continues to be self-implementing in nature, subject to enforcement by EPA or citizen groups. For facilities located within the boundaries of Native American reservations, such as the Navajo Nation where Four Corners is located, EPA is required to develop a federal permit program regardless of appropriated funds.

In 2018, EPA published a rule that constitutes "Phase One, Part One" of its ongoing reconsideration and revision of the 2015 CCR rule. The final Phase One, Part One rule extended the deadline to allow EGUs with unlined impoundments or that fail to meet the uppermost aquifer requirement to continue to receive coal ash until October 31, 2020, which was again extended by subsequent amendments. The rule also authorized a "Participating State Director" or EPA to approve suspension of groundwater monitoring requirements and to issue certifications related to the location restrictions, design criteria, groundwater monitoring, remedy selection and implementation. The rule also modified groundwater protection standards for certain constituents, which include cobalt, molybdenum, lithium, and lead without a maximum contamination level.

In 2019, EPA published a second round of proposed revisions, which are commonly referred to as the "Phase Two" revisions, to address reporting and accessibility to public information, "CCR piles" and "beneficial use" definitions, and the requirements for management of CCR piles. EPA reopened and extended the Phase Two comment period several times. To date, EPA has not yet finalized provisions in Phase Two related to beneficial use of CCR and CCR piles.

Since its Phase Two proposal, EPA has finalized three other rules addressing various CCR rule provisions. In 2020, EPA promulgated its proposed Holistic Approach to Closure Part A ("Part A"), which set forth a new deadline of April 11, 2021, for companies to initiate closure of unlined CCR impoundments. In accordance with the DC Circuit's vacatur of portions of the 2015 CCR Rule, Part A also changed the classification of compacted soil-lined or clay-lined surface impoundments from "lined" to "unlined", triggering closure or retrofit requirements for those impoundments. In addition, Part A delineated a process for owners/operators to submit requests for alternative closure deadlines.

EPA also issued the Holistic Approach to Closure Part B ("Part B") in 2020, which delineated the process for owners/operators to submit alternate liner demonstrations for clay-lined surface impoundments that could otherwise meet applicable requirements. This rule did not include beneficial use of CCR for closure, which EPA explained would be addressed in subsequent rulemaking actions. On May 18, 2023, EPA published a proposed rule establishing the regulatory requirements for inactive surface impoundments at inactive facilities and a new category of regulated unit called a CCR management unit ("CCRMU"), including groundwater monitoring, corrective action, closure, and post-closure care requirements for all CCR management units (regardless of how or when that CCR was placed), and several technical corrections to the existing regulations. Comments on the proposed rule were due July 17, 2023.

On May 8, 2024, EPA published a final rule that extended federal CCR regulatory requirements to (1) inactive CCR surface impoundments at inactive utilities and (2) CCRMU (Legacy Rule), including CCR impoundments and landfills that closed prior to the effective date of the 2015 CCR rule, inactive CCR landfills, and other areas where CCR was managed directly on the land. The rule became effective on November 8, 2024. EPA included deferral options for smaller CCRMU containing between one and 1,000 tons of CCR, CCRMU located beneath critical infrastructure or large buildings or structures vital to the continuation of current site activities, and CCRMU that closed prior to the effective date of the new rule (subject to certain eligibility conditions). EPA also codified the controversial definitions of infiltration and liquids that were litigated in the DC Circuit. Six petitions for review of the Legacy Rule were filed and were consolidated into one case by the DC Circuit. The Utility Solid Waste Activities Group, of which TXNM is a member, is a petitioner jointly with the National Rural Electric Cooperative Association, and American Public Power Association. The U.S. Supreme Court denied a requested stay of the rule by East Kentucky Power Cooperative. The DC Circuit agreed to hold the case in abeyance pending the outcome of EPA's reconsideration of the Legacy Rule, with status reports due on March 16, 2026, and at 90-day intervals thereafter. On July 22, 2025, EPA published a final rule and companion proposal revising the compliance deadlines for CCRMU requirements under the Legacy Rule. In September 2025, EPA withdrew the direct final rule due to adverse comments but subsequently issued a final extension rule on February 6, 2026, delaying the deadline to complete the "Facility Evaluation Report Part 1" until February 9, 2027, and extending all subsequent deadlines, as well. The final extension rule was published in the Federal Register on February 10, 2026.

As of the effective date of the Legacy Rule, one CCRMU was identified at SJGS. SJGS is required, at a minimum, to conduct a two-part evaluation of historic and current CCRMUs with reporting due dates of February 9, 2027, and February 8, 2028 (based on the new final extension rule), with each report posted to a company website by the due date.

At this time, PNM is still evaluating the financial impacts of this final regulation for Four Corners. Initial CCRMU site surveys and final site investigation reports are expected to be finalized by February 9, 2027. Based on the information available to the Company at this time, PNM cannot reasonably estimate the fair value of the entire CCRMU ARO. PNM cannot predict the outcome of the CCRMU site evaluations and investigations, or how these outcomes might affect the associated costs, which might have a material impact on PNM's operations, financial position, or cash flows.

In 2020, EPA published a proposed rule establishing a federal permitting program for the handling of CCR within the boundaries of Native American reservations and in states without their own federally authorized state programs. Permits for units within the boundaries of Native American reservations would be due 18 months after the effective date of the rule. EPA has not yet finalized the federal permitting program rule. EPA has coordinated with the affected permits for the three facilities with CCR disposal units located on Native American lands. PNM cannot predict the outcome of EPA's rulemaking activity or the outcome of any related litigation, and whether or how such a ruling would affect operations at Four Corners.

EPA's CCR rule does not cover mine placement of coal ash. In the preamble to its 2015 rule, EPA explained that the OSM and, as necessary, EPA would address the management of CCR in mine fills in a separate regulatory action, recognizing OSM's expertise in this area. EPA's decision to defer to OSM was based on a recommendation from the National Academy of Sciences ("NAS"), which was commissioned by Congress in 2006 to investigate the health, safety and environmental risks associated with the use of CCR for mine reclamation. The NRC report recommended that enforceable federal standards be established for the disposal of CCR in mine fills to ensure that states have specific authority and that states implement adequate safeguards. In 2007, OSM published an advance notice of proposed rulemaking on the placement of CCR at mine sites. In that notice, OSM explained its intent to develop the proposed regulations based on its existing authority under the Surface Mining Control and Reclamation Act. Since 2007, however, OSM has not taken any further action to advance this rulemaking. PNM cannot predict the outcome of OSM's proposed rulemaking regarding CCR regulation, including mine placement of CCRs, or whether OSM's actions will have a material impact on PNM's operations, financial position, or cash flows.

As noted above, SJGS does not operate any onsite CCR impoundments or landfills that are regulated under the 2015 CCR rule, and as of November 8, 2024, identified only one CCRMU that would potentially be regulated under the Legacy Rule. The CCR has since been removed from that unit and PNM will conduct the requisite site investigation reports. PNM would seek recovery from its retail customers of all CCR costs for jurisdictional assets that are ultimately incurred.

Utilities that own or operate CCR disposal units, such as those at Four Corners, as indicated above, were required to collect sufficient groundwater sampling data to initiate a detection monitoring program. Four Corners completed the analysis for its CCR disposal units, which identified several units that needed corrective action or needed to cease operations and initiate closure by April 11, 2021. Work is ongoing. Four Corners continues to gather additional groundwater data and perform remedial evaluations and activities. At this time, PNM does not anticipate its share of the cost to complete these corrective actions to close the CCR disposal units, or to gather and perform remedial evaluations on groundwater at Four Corners, will have a significant impact on its operations, financial position, or cash flows.

Other Commitments and Contingencies

Coal Supply

Four Corners

APS purchases all of Four Corners' coal requirements from NTEC, an entity owned by the Navajo Nation, under the Four Corners CSA that expires in 2031. The coal comes from reserves located within the Navajo Nation. The contract provides for pricing adjustments over its term based on economic indices and certain minimum payments that may be required if no deliveries of coal are taken. As of December 31, 2025, those minimum payments were $41.1 million for 2026, $85.7 million for 2027 and 2028, $91.0 million for 2029 and 2030, and $24.5 million for 2031. PNM's share of the coal costs is being recovered through the FPPAC.

Coal Mine Reclamation

As indicated under Coal Combustion Residuals Waste Disposal above, SJGS disposed of CCRs in the surface mine pits adjacent to the plant and Four Corners disposes of CCRs in ponds and dry storage areas.

Under the terms of the SJGS CSA, PNM and the other SJGS owners are obligated to compensate WSJ

LLC for all reclamation costs associated with the supply of coal from the San Juan mine. PNM and Westmoreland have entered into an agreement under which mine reclamation services for SJGS would be provided. A mine reclamation cost study was completed in the first quarter of 2024 and PNM remeasured its liability, which resulted in an increase in overall reclamation costs of $20.9 million, due primarily to higher inflationary factors. As a result, PNM recorded the increase in the liability related to the underground mine of $17.0 million as a regulatory asset on the Consolidated Balance Sheets. Due to the NMPRC cap on the amount that can be collected from retail customers for final reclamation of the surface mines at $100.0 million, PNM was required to record $4.0 million of the increase related to the surface mine liability plus an additional $0.5 million, related to other costs, as a regulatory disallowance on the Consolidated Statements of Earnings for the year ended December 31, 2024. In the third quarter of 2024, PNM and Westmoreland amended the mine reclamation services agreement to update the base rates for the costs of reclamation activities, which resulted in an increase in overall reclamation costs of $12.1 million. As a result, PNM recorded the increase in the liability related to the underground mine of $6.0 million as regulatory assets on the Consolidated Balance Sheets and the increase of $6.1 million related to the surface mine as a regulatory disallowance on the Consolidated Statements of Earnings for the year ended December 31, 2024.

In 2025, PNM and Westmoreland amended the mine reclamation services agreement to update the capital recovery charges due in each year from 2025 through 2028, which resulted in an increase in overall reclamation costs. As a result, PNM recorded increases in the liabilities related to the underground mine of $0.2 million and the surface mine of $0.2 million. PNM recorded the increase in the liability related to the underground mine as a regulatory asset on the Condensed Consolidated Balance Sheets at December 31, 2025. PNM recorded the increase related to the surface mine liability as a regulatory disallowance on the Consolidated Statements of Earnings for the year ended December 31, 2025.

PNM’s estimate of the costs necessary to reclaim the mine that serves SJGS is subject to many assumptions, including the timing of reclamation, generally accepted practices at the time reclamation activities occur, and current inflation and discount rates. PNM cannot predict the ultimate cost to reclaim the mine that serves SJGS and would seek to recover all costs related to reclaiming the underground mine from its customers but could be exposed to additional loss related to surface mine reclamation. In connection with certain mining permits relating to the operation of the San Juan mine, Westmoreland was required to post reclamation bonds of $118.7 million with the NMMMD. In order to facilitate the posting of reclamation bonds by sureties on behalf of Westmoreland, TXNM entered into the WFB LOC Facility under which letters of credit aggregating $19.3 million are outstanding as of December 31, 2025.

A coal mine reclamation study for the surface mine that serves Four Corners was completed in December 2024. The study reflected operation of the mine through 2031, the term of the Four Corners CSA. PNM remeasured its liability, which resulted in a decrease in overall reclamation costs of $1.6 million, due primarily to lower overhead costs, contractor management costs, and taxes and royalties. Due to the NMPRC cap on the amount that can be collected from retail customers for final reclamation of the surface mines at $100.0 million, PNM recorded the decrease related to the surface mine liability as a reduction in regulatory disallowance on the Consolidated Statements of Earnings for the year ended December 31, 2024. In 2025, APS provided an update to the cumulative MMBTU consumption for Four Corners for the purpose of allocating final mine reclamation costs. Based on the consumption outlook, PNM’s forecasted share of final reclamation costs was reduced from 9.755% to 9.096%. As a result, PNM recorded a decrease in the liability related to the surface mine of $0.9 million on the Condensed Consolidated Balance Sheets at December 31, 2025. This decrease is also recorded as a $0.9 million reduction in regulatory disallowance on the Consolidated Statements of Earnings for the year ended December 31, 2025.

Based on the most recent estimates, PNM’s remaining payments for mine reclamation, in future dollars, are estimated to be $30.6 million for the surface mines at both SJGS and Four Corners and $63.1 million for the underground mine at SJGS as of December 31, 2025. At December 31, 2025 and 2024, liabilities, in current dollars, of $20.8 million and $38.3 million for surface mine reclamation and $55.2 million and $52.9 million for underground mine reclamation were recorded in other deferred credits.

The SJGS owners are parties to a reclamation trust funds agreement to provide financial assurance for post-term coal mine reclamation obligations. The trust funds agreement requires each owner to enter into an individual trust agreement with a financial institution as trustee, create an irrevocable reclamation trust, and meet year-end funding targets set by funding curves that are approved by the SJGS ownership. PNM began using its mine reclamation trust to pay for final mine reclamation costs in April 2023. Because the trust agreement requires meeting specific funding targets at year end, it may be necessary for PNM to make additional contributions to meet those targets. PNM funded $7.0 million in 2025, $27.3 million in 2024, and $2.7 million in 2023. Based on PNM's reclamation trust fund balance at December 31, 2025, current forecasts, and current funding curve targets, PNM does not anticipate making any contributions in 2026 or 2027.

Under the Four Corners CSA, PNM is required to fund its share of estimated final reclamation costs in annual installments into an irrevocable escrow account solely dedicated to the final reclamation cost of the surface mine at Four Corners. PNM did not make any contributions to the escrow account in 2025. PNM funded $3.2 million in 2024 and $0.2 million in 2023 and anticipates providing additional funding of $0.5 million in 2026 and $0.5 million in 2027.

PNM recovers from retail customers' reclamation costs associated with the underground mine. However, the NMPRC capped the amount collected from retail customers for final reclamation of the surface mines at $100.0 million for both SJGS and Four Corners. If future estimates increase the liability for surface mine reclamation, the excess would be expensed at that time. The impacts of changes in New Mexico state law as a result of the enactment of the ETA and regulatory determinations made by the NMPRC may also affect PNM's financial position, results of operations, and cash flows. See additional discussion regarding PNM's SJGS and Four Corners Abandonment Applications in Note 17. PNM is currently unable to determine the outcome of these matters.

SJGS Decommissioning

On November 9, 2021, the San Juan County Commission approved the Coal-Fired Electricity Generating Facility Demolition and Remediation Ordinance ("Ordinance 121"), requiring the full demolition of SJGS upon its complete and permanent closure. Ordinance 121 required the SJGS owners to submit a proposed demolition and remediation plan no later than three months after SJGS was retired. The SJGS owners submitted the decommissioning and remediation plan on December 28, 2022. In connection with restructuring of the SJGS ownership on December 31, 2017, PNM and the other SJGS owners entered into the San Juan Decommissioning and Trust Funds Agreement, which requires PNM to fund its ownership share of final decommissioning costs into an irrevocable trust. Under the agreement, PNM made an initial funding of $14.7 million in December 2022 and made additional contribution of $7.0 million in 2024 and $4.7 million in 2025. The amount and timing of additional trust funding is subject to revised decommissioning cost studies and agreement among the SJGS owners. PNM began using its decommissioning trust to pay for demolition and decommissioning costs in October 2023. PNM has posted a surety bond in the amount of $46.0 million in connection with certain environmental decommissioning obligations and must maintain the bond or other financial assurance until those obligations are satisfied. The surety bond only represents a liability if the SJGS owners fail to deliver on its contractual liability.

PNM records its share of the SJGS decommissioning obligation as an ARO on its Consolidated Balance Sheets. Studies on the decommissioning costs of SJGS are performed periodically and revisions to the ARO liability are recorded. In the third quarter of 2022, a new decommissioning cost study was completed, which required PNM to remeasure its SJGS decommissioning ARO. The new study resulted in an estimated decrease to PNM's share of the decommissioning obligation of $21.1 million, which was recorded in September 2022.

On July 29, 2025, PNM received a letter from the NMED indicating that the NMED designated PNM as a responsible party and requiring a Stage 1 Abatement Plan ("S1AP") proposal for SJGS for groundwater and soil contamination associated with former operations at SJGS. On November 26, 2025, PNM submitted the S1AP to NMED that was approved on February 9, 2026. The S1AP estimates site investigation and monitoring to be completed by the first quarter of 2027. PNM is currently unable to determine the outcome of this matter.

PVNGS Liability and Insurance Matters

Public liability for incidents at nuclear power plants is governed by the Price-Anderson Nuclear Industries Indemnity Act, which limits the liability of nuclear reactor owners to the amount of insurance available from both commercial sources and an industry-wide retrospective payment plan. The insurance limit is subject to an adjustment every five years based upon the aggregate percentage change in the Consumer Price Index. The most recent adjustment took effect on January 1, 2024. As of that date, in accordance with this act, the PVNGS participants are insured against public liability exposure for a nuclear incident up to $16.3 billion per occurrence. PVNGS maintains the maximum available nuclear liability insurance in the amount of $500 million, which is provided by American Nuclear Insurers. The remaining $15.8 billion is provided through a mandatory industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, PNM could be assessed retrospective premium adjustments. The maximum retrospective premium per reactor under the program for each nuclear liability incident is $165.9 million, subject to a maximum annual premium of $24.7 million per incident. Based on PNM's ownership interest in the three units, PNM's maximum retrospective premium per incident for all three units is $36.3 million, with a maximum annual payment limitation of $5.4 million, to be adjusted periodically for inflation.

The PVNGS participants maintain insurance for damage to and decontamination of, property at PVNGS in the aggregate amount of $2.8 billion, a substantial portion of which must first be applied to stabilization and decontamination. These coverages are provided by Nuclear Electric Insurance Limited ("NEIL"). The primary policy offered by NEIL contains a sublimit of $2.25 billion for non-nuclear property damage. If NEIL's losses in any policy year exceed accumulated funds, PNM is subject to retrospective premium adjustments of $5.3 million. The insurance coverages discussed in this, and the previous paragraph are subject to certain policy conditions, sublimits, and exclusions.

(17) Regulatory and Rate Matters

The Company is involved in various regulatory matters, some of which contain contingencies that are subject to the same uncertainties as those described in Note 16.

TXNM

Merger Proceedings

On August 25, 2025, TXNM filed applications for approval of its proposed Merger with Blackstone Infrastructure (Note 22) with the NMPRC, PUCT, and FERC. In addition to strong governance and oversight provisions, the applications include the following benefits for PNM and TNMP's customers:

Application to the NMPRC

- $105.0 million in retail rate credits to be paid over four years
- $10.0 million in additional contributions to the PNM Good Neighbor Fund to be paid over 10 years
- $35.0 million in economic development funding to be paid over 10 years
- $25.0 million commitment to innovative technologies to support New Mexico's transition to carbon-free energy
- PNM's continued strong community involvement and charitable giving

The NMPRC does not have a statutory timeframe for consideration of the application. On December 5, 2025, the deadline for intervention passed with 19 parties intervening in the matter. A hearing has been scheduled for May 4-15, 2026.

On February 6, 2026, a motion and brief for order was filed, directing the applicants to show cause and for other relief in the pending application with the NMPRC. The motion alleges that the purchase of $400.0 million of TXNM common stock (Note 7) violated Section 62-6-12 of the Public Utility Act because PNM did not receive prior approval of the purchase from the NMPRC. TXNM and PNM believe that the allegations in the motion do not constitute a violation of the Public Utility Act and filed responses in opposition to the motion on February 18, 2026. PNM cannot predict the outcome of this matter.

Application to the PUCT

- Rate credits of $35.0 million to be paid over four years
- $10.0 million in economic development funding to be paid over 10 years
- $5.0 million in additional community support over 10 years to enhance charitable giving

On December 11, 2025, TXNM and Blackstone Infrastructure reached a unanimous settlement with parties in its Merger proceeding filed with the PUCT. Terms of the settlement include additional financial oversight, corporate governance and regulatory protections that favor local communities and the current workforce.

Additionally, the settlement removed the $10.0 million in economic development and the $5.0 million in charitable giving and increased the rate credits from $35.0 million to $45.5 million to be paid over four years. The settlement was approved by the PUCT on February 6, 2026.

Application to the FERC

On October 24, 2025, a protest was filed arguing that the proposed Merger posed significant risk of unlawful cross-subsidization, especially benefitting Blackstone Infrastructure's data centers and energy affiliates, and could harm competition, rates, and regulatory oversight. On November 10, 2025, TXNM and Blackstone Infrastructure filed a response contesting the arguments made in the protest. On December 23, 2025, FERC issued a deficiency letter requesting additional information on any ring-fencing provisions or regulations in place to protect customers from inappropriate cross-subsidization. On January 13, 2026, a response was submitted detailing the extensive ring-fencing provisions in place and relevant regulations set by the NMPRC and the PUCT.

On February 20, 2026, FERC approved the proposed Merger concluding that there is no adverse effect on competition, no adverse rate impacts, and no regulatory gap. FERC rejected claims related to data centers, private equity ownership, and speculative cross-subsidization relying on existing state ring-fencing protections in New Mexico and Texas.

PNM

New Mexico General Rate Case

2025 Rate Request

On June 14, 2024, PNM filed an application with the NMPRC for a general increase in retail electric rates. The proposed base rate changes would be implemented in two phases, with the first phase effective July 1, 2025, and the second phase effective January 1, 2026. Key aspects of PNM's request include:

- Recovery on total rate base of $3.0 billion, based on a FTY with the 12 months ending June 30, 2026
- An increase of $174.3 million in retail revenues, comprised of a $92.2 million increase in base rates and a $82.1 million increase in revenues collected under PNM's FPPAC
- Drivers of revenue deficiency:
    - Needed investments across distribution, transmission, and generation facilities to ensure safe, reliable delivery of electricity
    - Increased operations and maintenance expenses to meet operational needs, including wildfire risk mitigation
    - Costs associated with ESAs, previously approved by the NMPRC, necessary to serve our customers
    - ROE of 10.45%
    - Proposed capital structure of 52.5% equity
    - An increased cost of borrowing
    - Adjustments to Four Corners depreciation rates to recover remaining plant investments through July 2031, the expected abandonment date of the facility
- Proposed ratemaking treatment of ESAs to be recovered through PNM's FPPAC which began July 1, 2025

On November 26, 2024, PNM filed an unopposed comprehensive stipulation with the NMPRC. Key components agreed upon by the signatories are as follows:

- Overall revenue requirement increase of $105.0 million with the first phase effective July 1, 2025, and the second phase effective April 1, 2026
- ROE of 9.45%
- Capital structure of 51.0% equity
- Maintain currently approved depreciation rates for Four Corners as established in PNM's 2024 Rate Change and PNM's NM 2015 Rate Case
- Modification of PNM's current amortization period through December 31, 2028, on the unprotected Excess Deferred Federal Income Taxes ("EDFIT") regulatory liability to reflect amortization of remaining unprotected EDFIT through December 31, 2027

- Costs associated with ESAs shall be recovered through base rates
  - PNM will establish a regulatory asset or regulatory liability for the difference in actual ESA costs compared to the forecasted $82.1 million included in base rates in the test period and thereafter until new rates are effective from PNM's next general rate case filing. The regulatory asset or regulatory liability will be subject to NMPRC approval in PNM's next rate case
- PNM will establish a regulatory liability associated with investment tax credits for the Sandia energy storage system as proposed in its application
- PNM will establish a regulatory liability equal to the return on legacy meters currently included in rates, as the legacy meters are retired during PNM's deployment of its approved Grid Modernization Plan
- PNM will make a one-time shareholder contribution of $1.5 million to the Good Neighbor Fund

A hearing was held on February 17 and 18, 2025. On April 8, 2025, the hearing examiners issued a certification of stipulation recommending approval of the unopposed stipulation and on May 15, 2025, the NMPRC issued a final order adopting the unopposed stipulation. This matter is now concluded.

2024 Rate Change

On December 5, 2022, PNM filed an application with the NMPRC for a general increase in retail electric rates including recovery on total rate base of $2.7 billion based on a calendar year 2024 FTY, an increase of $63.8 million in retail non-fuel revenues, and an ROE 10.25%. The application also proposed ratemaking treatment of PVNGS Leased Interest and testimony supporting the prudence of PNM's decisions to renew the five leases and repurchase 64.1 MW of PVNGS Unit 2 capacity.

On January 3, 2024, the NMPRC issued a final order authorizing PNM to implement an increase in non-fuel base rates of $15.3 million, effective for service beginning January 15, 2024. The final order included:

- A ROE of 9.26%
- A capital structure of 49.61% equity, 50.10% debt, and 0.29% preferred stock
- Finding of imprudence regarding PNM's decision to remain in Four Corners and a remedy for the imprudence resulting in a disallowance of $81.0 million to PNM's total Four Corners net book value
- Approval of $51.3 million of PNM's requested $96.3 million regulatory asset for PVNGS undepreciated investments, but disallowance of a return on the remaining $45.0 million or any CWIP associated with it
- Requiring that the $38.4 million regulatory liability associated with leased capacity at PVNGS after the Unit 1 lease expired on January 15, 2023, be returned to ratepayers over two years through a separate rate rider
- The approval of new depreciation rates, reflecting shorter useful lives, of PNM's gas plants with service lives and depreciable lives extending beyond January 1, 2045, which would include PNM's La Luz and Luna generating stations
- The approval of PNM's TOD pilot program, with a requirement to make annual compliance filings and to adjust certain rate schedules

As a result of the final order, PNM recorded a regulatory disallowance of $55.5 million on the Consolidated Statement of Earnings and a corresponding reduction to Utility Plant in the year ended December 31, 2023, after accounting for previous impairments, to reflect the remedy adopted in the Final Order for Four Corners. In addition, PNM had recorded a reduction to electric operating revenues of $38.4 million with a corresponding increase to current regulatory liability of $19.2 million and deferred regulatory liability of $19.2 million for the PVNGS rate refunds that are being returned to customers over a two-year period ending March 2026. PNM had also recorded a regulatory disallowance of $8.2 million and a corresponding reduction to Utility Plant for the disallowance of CWIP from PVNGS.

In March 2024, notice of appeals were separately filed with the NM Supreme Court by NEE and PNM, and a joint notice of appeal was filed by the NM Department of Justice, Bernalillo County, and ABCWUA. NEE's appeal was subsequently consolidated with the joint notice of appeal. In the statements of issues submitted in the parties' appellate dockets, PNM took issue with the NMPRC's ruling on capital structure; other appellants primarily challenged the NMPRC rulings related to Four Corners and Palo Verde cost recovery. On June 20, 2025, PNM filed an uncontested motion to dismiss its appeal. The NM Supreme Court granted PNM's uncontested motion to dismiss its appeal, and on September 25, 2025, issued a ruling rejecting the consolidated appeal and upholding the NMPRC's final order. This matter is now concluded.

Renewable Energy Portfolio Standard

As discussed in Note 16, the ETA amends the REA including removal of diversity requirements and certain customer caps and exemptions relating to the application of the RPS under the REA. The REA provides for streamlined proceedings for approval of utilities' renewable energy procurement plans, assures that utilities recover costs incurred consistent with approved procurement plans, and requires the NMPRC to establish a Reasonable Cost Threshold ("RCT") for the procurement of renewable resources to prevent excessive costs being added to rates. The ETA sets a RCT of $60 per MWh, adjusted for inflation, using an average annual levelized resource cost basis. PNM makes renewable procurements consistent with the NMPRC approved plans and recovers certain renewable procurement costs from customers through the renewable energy rider billed on a KWh basis.

The following sets forth PNM's revenues recorded for the renewable energy rider:

Effective date	Proposed Revenue Collection	Annual Revenues Recorded
	(In millions)	
January 1, 2023	$61.0	$56.9
January 1, 2024	59.0	52.0
January 1, 2025	58.7	57.7

Under the renewable rider, if PNM's earned rate of return on jurisdictional equity in a calendar year, adjusted for items not representative of normal operations, exceeds the NMPRC-approved rate by 0.5%, PNM is required to refund the excess to customers during May through December of the following year. PNM did not exceed such limitation in 2024 and does not expect to exceed the limitation in 2025. On May 30, 2025, PNM filed its application for its 2026 renewable energy procurement plan, requesting to collect $54.3 million for the year. On September 25, 2025, the Hearing Examiners issued an RD recommending approval of PNM's application with no significant modifications and on October 30, 2025, the NMPRC issued a Final Order approving the application as filed.

Energy Efficiency and Load Management

Program Costs and Incentives/Disincentives

The EUEA requires public utilities to achieve specified levels of energy savings and to obtain NMPRC approval to implement energy efficiency and load management programs. The EUEA also requires the NMPRC to remove utility disincentives to implementing energy efficiency and load management programs and to provide incentives for such programs. The EUEA was amended to, among other things, include a decoupling mechanism for disincentives, preclude a reduction to a utility's ROE based on approval of disincentive or incentive mechanisms, establish energy savings targets for the period 2021 through 2025, and require that annual program funding be 3% to 5% of an electric utility's annual customer bills excluding gross receipt taxes, franchise and right-of-way access fees, provided that a customer's annual cost does not exceed seventy-five thousand dollars.

In 2020, PNM received approval for energy efficiency and load management programs to be offered in 2021, 2022, and 2023. The program included an annual base incentive of 7.1% of the portfolio budget if PNM were to achieve energy savings of at least 80 GWh in a year. The incentive increases if PNM is able to achieve savings greater than 94 GWh in a year.

Program year	Annual budget
	(In millions)
2021	$31.4
2022	31.0
2023	29.6

In 2024, PNM received approval for energy efficiency and load management programs to be offered in 2024, 2025, and 2026 (the "2024 Plan"). The 2024 Plan proposed to continue ten existing energy efficiency programs with modifications and an annual base incentive of 7.1% of the portfolio budget and a sliding scale that provides additional incentive for additional energy saved as a percentage of program cost, up to the maximum allowed by the energy efficiency rule which for PNM is 8.82%.

Program year	Annual budget (In millions)
2024	$34.5
2025	35.4
2026	36.5

On December 18, 2025, the NMPRC approved PNM's motion requesting an increase to the previously approved 2025 annual budget of approximately 10% to $38.9 million.

Integrated Resource Plans

NMPRC rules require that investor-owned utilities file an IRP every three years that covers a 20-year planning period and contains an action plan covering the first three years of that period. The IRP establishes a collaborative facilitated process for a utility and stakeholders to agree on a statement of need for potential new or additional resources, as well as an action plan to guide procurement or development of resources to meet the stated need. A most-cost-effective portfolio of resources shall be derived from the statement of need analysis. The statement of need and action plan must be accepted before the utility begins the resource solicitation process pursuant to the IRP Rule. Following acceptance of the statement of need and action plan, a utility will provide the NMPRC and intervenors drafts of the RFP and a timeline for issuing, receiving, evaluating, and ranking bids. The NMPRC will then appoint an Independent Monitor ("IM") to oversee the RFP process, which allows for parties and the IM to comment on the RFP consistency with the IRP, after which the utility issues the RFP. Within 120 days of receiving bids the utility shall provide the IM with results including pricing and non-price evaluation criteria, ranking of bids, chosen portfolio and alternatives that also meet the needs; the IM then rules on the fairness of the RFP execution. Acceptance of the statement of need and action plan will not constitute a finding of prudency or pre-approval of costs associated with the additional resources. Following the RFP and IM processes, the utility may apply for approvals, and any costs incurred to implement the action plan will be considered in a general rate case and/or resource acquisition proceeding.

2023 IRP

On December 15, 2023, PNM filed its 2023 IRP with a continued focus on a carbon-free energy system by 2040. The plan highlighted the need for the sustained addition of significant resources over the next two decades, replacing retiring or expiring capacity, meeting concurrent load growth, while reducing the carbon intensity of PNM's portfolio. On April 4, 2024, the NMPRC accepted PNM's 2023 IRP.

On December 30, 2024, PNM issued its 2029-2032 RFP for at least 900 MW of new energy resources to come online between 2029 and 2032, with at least 500 MW needed by 2030. The RFP is consistent with the needs identified in PNM's 2023 IRP, which identified a range of 900 to 2,900 MW of new capacity needed by 2032, depending on the type of resources selected. The 2029-2032 RFP is anticipated to identify potential replacement resources for PNM's current natural gas generation capacity as well as PNM's ownership interest in Four Corners. On January 2, 2026, PNM filed a Notice of Material Event for the 2023 IRP to inform the NMPRC of its intent to issue a supplemental RFP for gas-fired resources in response to new customer requirements that have accelerated and increased energy demands beyond previously forecasted resources. On February 4, 2026, the IM appointed to the 2029-2032 RFP concluded that PNM appropriately evaluated the bids, made reasonable portfolio selection decisions, and overall, the RFP process was conducted in a fair, transparent manner that was in compliance with regulatory requirements.

Abandonment Applications made under the ETA

As discussed in Note 16, the ETA provides for a transition from fossil-fueled generating resources to renewable and carbon-free resources by allowing utilities to issue energy transition bonds related to the retirement of certain coal-fired generating facilities, to qualified investors.

SJGS Abandonment Application

In 2019, PNM filed a Consolidated Application for the Abandonment and Replacement of SJGS and Related Securitized Financing Pursuant to the ETA. In 2023, PNM, along with intervening parties, reached a unanimous settlement which was approved by the NMPRC. As a result, PNM recorded a $128.7 million reduction to electric operating revenues in the Consolidated Statement of Earnings and a corresponding current regulatory liability on the Consolidated Balance Sheets as of and for the year ended December 31, 2023. In addition, PNM recorded a regulatory disallowance of $3.3 million on the Consolidated Statement of Earnings and a corresponding decrease to deferred regulatory assets on the Consolidated Balance Sheets as of and for the year ended December 31, 2023, to reflect PNM's agreement to withdraw its request for regulatory assets associated with prefunding of ETA state administered funds and legal costs associated with this matter.

Four Corners Abandonment Application

In 2020, PNM entered into the Four Corners Purchase and Sale Agreement with NTEC, pursuant to which PNM agreed to sell its 13% ownership interest (other than certain transmission assets) in Four Corners to NTEC, contingent upon NMPRC approval. In connection with the sale, PNM would make payments of $75.0 million to NTEC for relief from its obligations under the coal supply agreement for Four Corners after December 31, 2024. PNM made an initial payment to NTEC of $15.0 million in November 2020, subject to refund with interest upon termination of the Four Corners Purchase and Sale Agreement prior to closing. Under the terms of the Four Corners Purchase and Sale Agreement, upon receipt of the NMPRC approval, PNM was expected to make a final payment of $60.0 million.

On January 8, 2021, PNM filed the Four Corners Abandonment Application, which sought NMPRC approval to exit PNM's share of Four Corners as of December 31, 2024, and issuance of approximately $300 million of Securitized Bonds as provided by the ETA. On December 15, 2021, the NMPRC issued a final order denying approval of the Four Corners Abandonment Application and the corresponding request for issuance of securitized financing. On December 22, 2021, PNM filed a Notice of Appeal with the NM Supreme Court of the NMPRC decision to deny the application and on July 6, 2023, the NM Supreme Court affirmed the NMPRC decision concluding that the NMPRC reasonably and lawfully denied PNM's application for abandonment. As a result of the NM Supreme Court's decision to uphold the NMPRC's denial, the Consolidated Statements of Earnings for the year ended December 31, 2023, reflect a regulatory disallowance of $3.7 million. On April 23, 2024, PNM filed an interim notice informing the NMPRC that PNM's updated analysis indicates it is in the interest of customers for PNM to remain as a participant in Four Corners until the expiration of the current coal supply agreement in 2031. In August 2024, PNM and NTEC terminated the Four Corners Purchase and Sale Agreement and executed an agreement for the reimbursement of PNM's initial $15.0 million payment with interest, which was paid in 2024.

2028 Resource Application

On November 22, 2024, PNM filed an application with the NMPRC seeking approval of ESAs, a PPA, and a CCN for system resources in 2028 to be available to meet summer 2028 customer needs. PNM's request included:

- Two 150 MW ESAs
- A 167 MW PPA for the Valencia power plant through 2039
- A CCN for a 100 MW solar facility and a 30 MW battery to be PNM-owned and located in San Juan County; the request provides the opportunity to increase the 30 MW battery by an additional 20 MW

On March 12, 2025, PNM and intervening parties filed an unopposed comprehensive stipulation with the NMPRC. The stipulation supports approval of PNM's application, including the proposed option to increase the 30 MW battery by an additional 20 MW. On May 6, 2025, the hearing examiners issued a certification of stipulation recommending approval of the unopposed stipulation and on June 26, 2025, the NMPRC approved the unopposed stipulation. This matter is now concluded.

Grid Modernization Plan

In October 2022, in compliance with New Mexico Grid Modernization Statute, PNM filed its Grid Modernization Plan with the NMPRC. The projects included in the application improve customers' ability to customize their use of energy and ensure that customers, including low-income customers, are a top priority and will benefit consistent with the Grid Modernization Statute. PNM's proposal to modernize its electricity grid through infrastructure and technology improvements also increases the efficiency, reliability, resilience, and security of PNM's electric system. PNM's application included grid modernization investments of approximately $344 million for the first six years of a broader 11-year strategy. The approved rate rider will recover capital costs, operating expenses, and taxes associated with the investments included in the Grid Modernization Plan. On October 17, 2024, the NMPRC issued a final order largely approving PNM's Grid Modernization Plan with minor modifications.

On June 20, 2025, PNM filed its first annual Grid Modernization Plan Review to provide updates on year one implementation progress and outline planned activities for year two, in alignment with regulatory expectations. Additionally, PNM has updated key portions of the forecasted strategy including increasing investments from approximately $344 million to $367 million in the first six years, while decreasing projected operations and maintenance costs by approximately 18%. On February 26, 2026, the NMPRC approved PNM's first annual Grid Modernization Review and the updated year two revenue requirement. This matter is now concluded.

FERC Order 864

In November 2019, FERC issued Order No. 864, which required public utility transmission providers with transmission formula rates to revise those rates to account for changes resulting from the Tax Cuts and Jobs Act of 2017 (the "Tax Act"). PNM has already made revisions to its formula rate to account for Tax Act changes, and, as a result of the Order, PNM proposed additional changes to its formula rate to implement the remaining requirements of the Order. In July 2022, FERC issued an order finding that PNM had predominantly complied with the requirements but set aside certain matters for settlement and hearing procedures.

On November 22, 2023, PNM, on behalf of the settling parties, filed a settlement agreement with FERC resolving all issues. As a result of the settlement agreement, PNM recorded a decrease of $3.2 million to electric operating revenues and an increase to interest charges of $0.3 million on the Consolidated Statement of Earnings and an increase to other current liabilities of $3.5 million on the Consolidated Balance Sheets as of and for the year ended December 31, 2023. This matter is now concluded.

EDAM

PNM participates in the EIM, a real-time wholesale energy trading market operated by the CAISO, that enables participating electric utilities to buy and sell energy. EDAM is a voluntary day-ahead regional market that expands on CAISO's EIM market, which PNM plans on joining in the fall of 2027. On August 22, 2025, PNM filed an application with the NMPRC requesting approval to create a regulatory asset for the costs associated with joining the EDAM, which was approved in an accounting order issued on October 16, 2025. PNM expects to seek recovery of these costs in a future rate case.

Meta Platforms Inc. Data Center - Phase IV

PNM has a special service contract to provide service to Meta for a data center in PNM's service area. Meta's service requirements include the acquisition by PNM of a sufficient amount of new renewable energy resources and RECs to match the energy and capacity requirements of the data center. The cost of renewable energy procured is passed through to Meta under a rate rider. A special service rate is applied to Meta's energy consumption in those hours of the month when their consumption exceeds the energy production from the renewable resources.

On June 13, 2025, PNM filed an application with the NMPRC for an amended special service contract, PPAs, ESAs, special service rate, and an amended rate rider to service a new phase of the data center, the Greater Kudo, LLC Data Center. This amended special service contract requests:

- three 20-year solar PPAs totaling 290 MW
- three 20-year ESAs totaling 268 MW of storage
- a third revised and restated special service contract with Greater Kudo, LLC Data Center
- updates to the special service rate - Renewable Energy Resources, the Green Energy Rider, and the Production Cost Allocation Rider

On July 3, 2025, a procedural order was issued and on October 21, 2025, a prehearing conference was held where all parties agreed that a public hearing was unnecessary and that the evidence on record was sufficient to support a RD. On December 18, 2025, the NMPRC issued a final order approving PNM's application in its entirety.

BESS Project

On August 6, 2025, PNM filed an application with the NMPRC for approval of a CCN to construct, own, and operate 30 MWs of energy storage. The application consists of 6 MW batteries to be constructed at five existing PNM-owned solar facilities located in Otero County, San Miguel County, Luna County, and two sites in Valencia County. PNM estimates that the Battery Energy Storage System ("BESS") Project will cost $78.7 million and will assist in serving our summer peak season when operational. PNM expects to seek recovery of these costs in a future rate case.

SB 170 Projects

The enactment of Senate Bill 170 ("SB 170") allows a utility to defer costs of economic development projects that serve sites certified by the New Mexico Economic Development Department ("NMEDD"). On December 29, 2025, PNM filed an application with the NMPRC for approval of two economic development projects including the Westpointe and Mesa Del Sol Substations and the issuance of an accounting order to defer the costs of the projects as regulatory assets. The projects are estimated to cost $165.5 million and are expected to be reviewed in a future rate proceeding.

Rio Puerco-Pajarito-Prosperity CCN

On December 30, 2025, PNM filed an application with the NMPRC for approval of a CCN and a determination for a new right-of-way. The CCN encompasses a new 345 kV transmission line, existing station expansions, and a new substation. This project aims to enhance reliability and resilience in the Albuquerque area, facilitate the integration of renewable energy, and support economic development. On February 13, 2026, the NMPRC dismissed the application without prejudice and on February 25, 2026, PNM filed a new application for approval of the CCN providing additional clarity and more information on the project. The estimated cost of the project is approximately $247 million and is expected to be reviewed in a future rate proceeding.

TNMP

TNMP Base Rate Review

On November 14, 2025, TNMP filed a general rate proceeding with the PUCT (the "TNMP Base Rate Review") requesting recovery of $2.8 billion of rate base as of June 30, 2025, a requested ROE of 10.4%, and a 47.54% equity ratio. The TNMP Base Rate Review also includes increases in operations and maintenance expenses that are not recovered through semi-annual TCOS and DCRF filings, excludes increases in interest expense resulting from refinancing of debt associated with the proposed Merger, and requests recovery of $20.5 million associated with Hurricane Beryl restoration costs over a five-year period. If approved by the PUCT, the new rates are expected to become effective in mid-2026. A hearing has been set for March 9, 2026.

Energy Efficiency

TNMP recovers the costs of its energy efficiency programs through an energy efficiency cost recovery factor ("EECRF"), which includes projected program costs, under or over collected costs from prior years, rate case expenses, and performance bonuses (if the programs exceed mandated savings goals).

The following sets forth TNMP's EECRF increases:

Effective Date	Aggregate Collection Amount	Performance Bonus
	(In millions)	
March 1, 2023	$7.3	$1.9
March 1, 2024	6.6	1.2
March 1, 2025	7.0	1.3

On May 30, 2025, TNMP filed its request to adjust the EECRF to reflect changes in costs for 2026. On November 14, 2025, the PUCT approved the total amount requested, authorizing recovery of $8.1 million, including a performance bonus of $2.5 million based on TNMP's energy efficiency achievements in the 2024 plan year.

Transmission Cost of Service Rates

TNMP can update its TCOS rates twice per year to reflect changes in its invested capital although updates are not allowed while a general rate case is in process. Updated rates reflect the addition and retirement of transmission facilities, including appropriate depreciation, federal income tax and other associated taxes, and the approved rate of return on such facilities. The following sets forth TNMP's recent interim transmission cost rate increases:

Effective Date	Approved Increase in Rate Base	Annual Increase in Revenue
	(In millions)	
May 12, 2023	$150.5	$19.4
September 6, 2023	21.4	4.2
March 15, 2024	97.4	13.1
September 20, 2024	20.6	3.9
March 25, 2025	83.5	11.5
September 19, 2025	87.4	12.3

Periodic Distribution Rate Adjustment

PUCT rules permit interim rate adjustments to reflect changes in investments in distribution assets. Historically, distribution utilities have been restricted to a single, annual periodic rate adjustment through a DCRF submitted between April 1 and April 8 of each year as long as the electric utility was not earning more than its authorized rate of return using weather-normalized data. However, the recent passage of Senate Bill 1015 now permits DCRF proceedings to be filed twice per year with a 60-day administrative deadline that can be extended for 15 days on good cause. Additionally, a DCRF may be filed during a pending rate case proceeding as long as that DCRF request is not filed until the 185th day after the rate case proceeding was initiated. The following sets forth TNMP's recent interim distribution rate increases:

Effective Date	Approved Increase in Rate Base	Annual Increase in Revenue
	(In millions)	
September 1, 2023	$157.0	$14.5
July 28, 2024	205.9	15.6
November 17, 2024	43.7	7.7
June 29, 2025	176.6	25.0
December 29, 2025	18.9	1.8

HB 5247

On June 20, 2025, Texas House Bill 5247 ("HB 5247") was signed into law by Governor Gregg Abbott. HB 5247, which took effect immediately, added Section 36.216 to the Public Regulatory Act ("PURA 36.216"), authorizing certain electric utilities with total capital expenditures that exceeded 300 percent of annual depreciation in a calendar year, to elect, in the following calendar year, to file a single, annual proceeding to adjust nonfuel rates on a system-wide basis to reflect changes in transmission and distribution rates previously authorized under certain other interim rate mechanisms. A utility seeking to make this election under PURA 36.216 is required to file a notice with the PUCT informing them of its intent and provide supporting documentation of the applicable capital expenditures at least 60 days before filing the single, annual proceeding and correspondingly must notify the PUCT if the utility determines that it no longer qualifies for continued use of the election. Management has evaluated the application of HB 5247 and PURA 36.216 and determined that TNMP qualifies as the type of electric utility that would be eligible for the election. Upon completion of its general rate proceeding discussed above, TNMP expects to make its first comprehensive filing under Section 36.216 with a view towards recovering costs associated with eligible transmission and distribution investments that were placed into service after December 31, 2024, and that are not currently reflected in rates. In the interim, TNMP is recognizing a regulatory asset for costs associated with eligible transmission and distribution capital investments and is offsetting depreciation, property tax expense, and carrying costs within alternative revenue. At December 31, 2025 the regulatory asset associated with these costs totaled $17.5 million.

3G Meters Notice of Violation

In 2020, the PUCT established the COVID-19 Electricity Relief Program for electric utilities, REPs, and customers impacted by COVID-19. The program allowed providers to implement a rider to collect unpaid residential retail customer bills and to establish a regulatory asset for costs related to COVID-19. These costs included but were not limited to costs related to unpaid accounts.

In December 2023, TNMP and the PUCT reached a settlement agreement related to a notice of violation against TNMP primarily for estimating 3G meters during the period that TNMP was remediating the meters. TNMP maintained that the remediation efforts were impacted by supply chain and labor availability issues resulting from COVID-19. Pursuant to the settlement agreement, TNMP agreed to no longer pursue the recovery of COVID-19 related costs that were recorded as a regulatory asset. This resulted in a regulatory disallowance of $1.2 million recorded for the year ended December 31, 2023.

Hurricane Beryl

On July 8, 2024, Hurricane Beryl made landfall in the Texas Gulf Coast leaving approximately 116,000 customers in the TNMP service area without power. As of December 31, 2025 and 2024, TNMP had incurred $54.0 million and $53.1 million of costs, of which $33.5 million and $32.1 million had been recorded in Utility Plant and $20.5 million and $21.0 million had been recorded as a Regulatory Asset on the Consolidated Balance Sheets. These costs were included in the TNMP Base Rate Review filed on November 14, 2025.

System Resiliency Plan (“SRP”)

In 2023, the Texas Legislature enacted House Bill No, 2555 (“HB 2555”), permitting an electric utility to seek approval of, and cost recovery for, a system resiliency plan. On August 28, 2024, TNMP filed its first SRP with the PUCT designed to benefit customers through enhanced resiliency of its distribution system, as intended under HB 2555. The SRP includes approximately $600 million of capital investments and approximately $151 million of other related costs over three years and was developed using a comprehensive and data-driven approach which evaluated various types of resiliency events posing material risk to the safe and reliable operation of TNMP's distribution system. TNMP's service territory includes non-contiguous areas across different regions of Texas, ranging from small communities and rural areas to communities around large metropolitan areas, each with unique risks. Investments in the SRP are prioritized based on customer benefit, physical protection of infrastructure, foundational investments in operational and cybersecurity technologies, and wildfire risk reduction and are focused on lower-performing areas in the context of reliability. Eight different resiliency measures are outlined in the SRP with associated programs and infrastructure impacts to improve the system's ability to prevent, withstand, mitigate and/or more promptly recover from resiliency events: distribution system resiliency, distribution system protection modernization, vegetation management, wildfire mitigation, flood mitigation, enhanced operations system technology, cybersecurity, and physical security resiliency. Recovery of investments and costs are permissible primarily through semi-annual DCRF filings, with deferral of depreciation and other certain expenses until recovery begins.

On December 11, 2024, TNMP filed an unopposed settlement with the PUCT. The settlement includes $565.8 million of capital investments over 2025 through 2027, reflecting 94% of TNMP’s proposed plan investments. The settlement also encompasses $128.2 million of operations and maintenance expenses associated with several programs, including vegetation management and wildfire mitigation. On March 26, 2025, TNMP received the final order from the PUCT which included modifications reflecting capital investments of $545.8 million and $86.1 million of operating and maintenance costs. As of December 31, 2025, TNMP incurred

$10.3 million of operating and maintenance costs, all of which have been recorded as a Regulatory Asset on the Condensed Consolidated Balance Sheets. TNMP will seek collection of such costs in a future regulatory proceeding.

Sales and Use Tax Refund

On March 12, 2025, TNMP filed a refund claim with the Texas Comptroller's office for overpaid sales and use taxes primarily related to asset purchases. The $34.6 million refund claim covers periods from January 2022 to October 2024 and amounts received, net of consultant fees, are expected to be applied to 2025 TNMP capital projects. On September 22, 2025, TNMP received the requested refund net of $7.5 million in consultant fees; $24.7 million was applied to 2025 TNMP capital projects; $2.1 million to offset related interest expense; and $0.3 million for other related expenses.

(18) Income Taxes

Federal Income Tax Reform

In 2017, comprehensive changes in U.S. federal income taxes were enacted through legislation commonly known as the Tax Cuts and Jobs Act (the "Tax Act"). The Tax Act made many significant modifications to the tax laws, including reducing the federal corporate income tax rate from 35% to 21% effective January 1, 2018. The Tax Act also eliminated federal bonus depreciation for utilities, limited interest deductibility for non-utility businesses and limited the deductibility of officer compensation. During 2020, the IRS issued final regulations related to certain officer compensation and, in January 2021, issued final regulations on interest deductibility that provide a 10% "de minimis" exception that allows entities with predominantly regulated activities to fully deduct interest expenses.

As a result of the change in the federal income tax rate, the Company re-measured and adjusted its deferred tax assets and liabilities as of December 31, 2017. The portion of that adjustment not related to PNM's and TNMP's regulated activities was recorded as a reduction in net deferred tax assets and an increase in income tax expense. The portion related to PNM's and TNMP's regulated activities was recorded as a reduction in net deferred tax liabilities and an increase in regulatory liabilities.

Beginning February 2018, PNM's NM 2016 Rate Case reflected the reduction in the federal and state corporate income tax rates, including amortization of excess deferred federal and state income taxes. In accordance with the order in that case and amortization requirements of the tax laws, PNM is returning the protected portion of excess deferred federal income taxes to customers over the average remaining life of plant in service as of December 31, 2017. The remaining balance of the unprotected portion of excess deferred federal income taxes, which was being returned to customers over a period of approximately twenty-three years, will be returned over a five-year period when new rates go into effect from the 2024 Rate Change. Excess deferred state income taxes were returned to customers over a three-year period, which concluded in the first quarter of 2021. The approved settlement in the TNMP 2018 Rate Case includes a reduction in customer rates to reflect the impacts of the Tax Act beginning on January 1, 2019. TXNM, PNM, and TNMP amortized federal excess deferred income taxes of $25.7 million, $23.0 million, and $2.7 million in 2025.

On July 4, 2025, changes in U.S. federal income tax laws were enacted through the OBBBA. The OBBBA generally extends and makes permanent the changes from the Tax Act, including maintaining the 21% corporate tax rate, interest deductibility for regulated electric utilities, and state and local tax deductibility. The OBBBA also accelerates the phase-out of certain Inflation Reduction Act of 2022 energy tax credits and restricts the availability of credits for "foreign entities of concern." As a result, TXNM anticipates potentially higher costs associated with any future renewable energy development but does not expect other aspects of the OBBBA to have a material impact on its financial statements.

TXNM

TXNM's income taxes (benefits) consist of the following components:

	Year Ended December 31,		
	2025	2024	2023
	(In thousands)		
U.S. Income from continuing operations before income taxes (benefits)	$ 180,013	$ 280,240	$ 90,529
Current tax expense (benefit)			
U.S. federal	$ —	$ —	$ —
U.S. state	1,712	(1,984)	(2,841)
Total current tax expense (benefit)	1,712	(1,984)	(2,841)
Deferred tax expense (benefit)			
U.S. federal	6,284	13,042	(11,503)
U.S. state	2,360	10,630	(825)
U.S. amortization of accumulated investment tax credits	(169)	(170)	(1,181)
Total deferred tax expense (benefit)	8,475	23,502	(13,509)
Total income taxes (benefits)	$ 10,187	$ 21,518	$ (16,350)

TXNM's provision for income taxes (benefits) differed from the federal income tax computed at the statutory rate for each of the years shown. The differences are attributable to the following factors:

	Year Ended December 31,					
	2025		2024		2023	
	(In thousands except for rates)					
U.S. federal statutory income tax rate	$ 37,803	21.00%	$ 58,850	21.00%	$ 19,011	21.00%
U.S. federal						
Nontaxable and nondeductible items						
(Earnings) attributable to non-controlling interest in Valencia	(3,767)	(2.09)	(3,368)	(1.20)	(3,892)	(4.30)
Allowance for equity funds used during construction	(3,906)	(2.17)	(3,756)	(1.34)	(3,145)	(3.48)
Non-deductible compensation	1,999	1.11	1,450	0.52	1,659	1.83
Non-deductible merger related costs	—	—	—	—	(1,959)	(2.16)
Other	545	0.30	714	0.26	17	0.02
Tax Credits						
Research credits	(1,273)	(0.71)	(533)	(0.19)	(2,074)	(2.29)
Amortization of investment tax credits	(169)	(0.09)	(170)	(0.06)	(1,181)	(1.31)
Sale of NMRD	—	—	(15,713)	(5.61)	—	—
Other	—	—	(109)	(0.04)	(536)	(0.59)
Changes in unrecognized tax benefits	82	0.05	(155)	(0.06)	260	0.29
Changes in valuation allowances	1,356	0.75	890	0.32	1,183	1.31
Other adjustments						
Amortization of excess deferred income tax	(25,649)	(14.25)	(23,362)	(8.34)	(22,859)	(25.25)
Other	(50)	(0.03)	(50)	(0.02)	17	0.02
U.S. state income taxes (benefits), net of federal effect	3,216	1.79	6,830	2.44	(2,851)	(3.15)
Total income taxes (benefits)	$ 10,187	5.66%	$ 21,518	7.68%	$ (16,350)	(18.06)%

The components of TXNM's income taxes paid were:

	Year Ended December 31,		
	2025	2024	2023
	(In thousands)		
U.S. federal	$ —	$ —	$ —
U.S. state			
New Mexico	—	(1,707)	350
Texas	2,350	709	1,155
Total paid (refunded)	$ 2,350	$ (998)	$ 1,505

The components of TXNM's net accumulated deferred income tax liability were:

	December 31,	
	2025	2024
	(In thousands)	
Deferred tax assets:		
Net operating loss	$ 70,959	$ 31,592
Regulatory liabilities related to income taxes	74,169	82,702
Federal tax credit carryforwards	127,140	126,770
Regulatory disallowances	42,136	42,330
Regulatory liability SJGS retirement credits	20	40
Other	48,599	52,955
Total deferred tax assets	363,023	336,389
Deferred tax liabilities:		
Depreciation and plant related	(880,253)	(794,203)
Investment tax credit	(80,899)	(81,068)
Regulatory assets related to income taxes	(85,926)	(84,053)
Pension	(42,568)	(41,383)
Regulatory asset for shutdown of SJGS Units 2 and 3	(19,265)	(20,860)
Regulatory asset SJGS energy transition property	(83,601)	(85,365)
Regulatory asset PVNGS investment	(19,939)	(21,044)
PVNGS trusts	(47,214)	(48,421)
Other	(64,588)	(59,384)
Total deferred tax liabilities	(1,324,253)	(1,235,781)
Net accumulated deferred income tax liabilities	$ (961,230)	$ (899,392)

The following table reconciles the change in TXNM's net accumulated deferred income tax liability to the deferred income tax (benefit) included in the Consolidated Statement of Earnings:

	Year Ended December 31, 2025
	(In thousands)
Net change in deferred income tax liability per above table	$ 61,838
Change in tax effects of income tax related regulatory assets and liabilities	(11,079)
Amortization of excess deferred income tax	(25,649)
Tax effect of mark-to-market adjustments	389
Tax effect of excess pension liability	(17,024)
Adjustment for uncertain income tax positions	641
Reclassification of unrecognized tax benefits	(641)
Other	—
Deferred income tax (benefit)	$ 8,475

PNM

PNM's income taxes (benefits) consist of the following components:

	Year Ended December 31,		
	2025	2024	2023
		(In thousands)	
U.S. Income from continuing operations before income taxes (benefits)	$ 101,099	$ 237,469	$ 37,960
Current tax expense (benefit)			
U.S. federal	$ (9,044)	$ (7,005)	$ 9,518
U.S. state	(1,114)	(5,681)	(4,304)
Total current tax expense (benefit)	(10,158)	(12,686)	5,214
Deferred tax expense (benefit)			
U.S. federal	841	28,183	(22,951)
U.S. state	5,044	13,890	1,150
U.S. amortization of accumulated investment tax credits	(169)	(170)	(171)
Total deferred tax expense (benefit)	5,716	41,903	(21,972)
Total income taxes (benefits)	$ (4,442)	$ 29,217	$ (16,758)

PNM's provision for income taxes (benefits) differed from the federal income tax computed at the statutory rate for each of the years shown. The differences are attributable to the following factors:

	Year Ended December 31,					
	2025		2024		2023	
	(In thousands except for rates)					
U.S. federal statutory income tax rate	$ 21,231	21.00%	$ 49,868	21.00%	$ 7,972	21.00%
U.S. federal						
Nontaxable and nondeductible items						
(Earnings) attributable to non-controlling interest in Valencia	(3,767)	(3.72)	(3,368)	(1.42)	(3,892)	(10.25)
Allowance for equity funds used during construction	(2,038)	(2.01)	(2,739)	(1.15)	(2,065)	(5.44)
Non-deductible compensation	1,277	1.26	894	0.38	1,015	2.67
Other	(83)	(0.08)	(38)	(0.02)	(870)	(2.29)
Tax Credits						
Research credits	(1,170)	(1.16)	(475)	(0.20)	(1,985)	(5.23)
Other	(169)	(0.17)	(170)	(0.07)	(171)	(0.45)
Changes in unrecognized tax benefits	53	0.05	(163)	(0.07)	240	0.63
Changes in valuation allowances	136	0.14	(277)	(0.12)	(224)	(0.59)
Other adjustments						
Amortization of excess deferred income tax	(22,966)	(22.72)	(20,750)	(8.74)	(14,252)	(37.54)
Other	(50)	(0.05)	(49)	(0.02)	(34)	(0.09)
U.S. state income taxes (benefits), net of federal effect	3,104	3.07	6,484	2.73	(2,492)	(6.57)
Total income taxes (benefits)	$ (4,442)	(4.39)%	$ 29,217	12.30%	$ (16,758)	(44.15)%

The components of PNM's income taxes paid (refunded) were:

	Year Ended December 31,		
	2025	2024	2023
		(In thousands)	
U.S. federal	$ (10,774)	$ (2,262)	$ (4,794)
U.S. state			

New Mexico	(2,562)	(1,796)	(544)
Texas	—	—	—
Total paid (refunded)	$ (13,336)	$ (4,058)	$ (5,338)

The components of PNM’s net accumulated deferred income tax liability were:

	December 31, 2025	December 31, 2024
	(In thousands)	
Deferred tax assets:		
Net operating loss	$ 23,654	$ —
Regulatory liabilities related to income taxes	56,661	64,481
Federal tax credit carryforwards	97,915	93,481
Regulatory disallowance	42,136	42,330
Regulatory liability SJGS retirement credits	20	40
Other	24,368	35,650
Total deferred tax assets	244,754	235,982
Deferred tax liabilities:		
Depreciation and plant related	(655,362)	(582,089)
Investment tax credit	(80,899)	(81,068)
Regulatory assets related to income taxes	(77,648)	(75,464)
Pension	(37,820)	(36,678)
Regulatory asset for shutdown of SJGS Units 2 and 3	(19,265)	(20,860)
Regulatory asset SJGS energy transition property	(83,601)	(85,365)
Regulatory asset PVNGS investment	(19,939)	(21,044)
PVNGS Trusts	(47,214)	(48,421)
Other	(36,534)	(41,211)
Total deferred tax liabilities	(1,058,282)	(992,200)
Net accumulated deferred income tax liabilities	$ (813,528)	$ (756,218)

The following table reconciles the change in PNM’s net accumulated deferred income tax liability to the deferred income tax (benefit) included in the Consolidated Statement of Earnings:

	Year Ended 2025
	(In thousands)
Net change in deferred income tax liability per above table	$ 57,310
Change in tax effects of income tax related regulatory assets and liabilities	(10,678)
Amortization of excess deferred income tax	(22,966)
Tax effect of mark-to-market adjustments	(2)
Tax effect of excess pension liability	(17,024)
Adjustment for uncertain income tax positions	600
Reclassification of unrecognized tax benefits	(1,524)
Deferred income tax (benefit)	$ 5,716

TNMP

TNMP’s income taxes consist of the following components:

	Year Ended December 31, 2025	2024	2023
		(In thousands)	
U.S. Income from continuing operations before income taxes	$ 156,375	$ 130,642	$ 112,234
Current tax expense (benefit)			
U.S. federal	$ 10,188	$ (2,549)	$ 11,354
U.S. state	3,713	3,300	3,055
Total current tax expense	13,901	751	14,409
Deferred tax expense (benefit)			
U.S. federal	18,184	26,363	2,917
U.S. state	—	—	(29)
Total deferred tax expense	18,184	26,363	2,888
Total income taxes	$ 32,085	$ 27,114	$ 17,297

TNMP’s provision for income taxes differed from the federal income tax computed at the statutory rate for each of the periods shown. The differences are attributable to the following factors:

	Year Ended December 31, 2025		2024		2023	
			(In thousands except for rates)			
U.S. federal statutory income tax rate	$ 32,839	21.00%	$ 27,435	21.00%	$ 23,569	21.00%
U.S. federal						
Nontaxable and nondeductible items	(880)	(0.56)	(86)	(0.07)	(149)	(0.13)
Tax Credits						
Research credits	(103)	(0.07)	(58)	(0.04)	(90)	(0.08)
Changes in unrecognized tax benefits	28	0.02	9	0.01	20	0.02
Changes in valuation allowances	(50)	(0.03)	(180)	(0.14)	140	0.12
Other adjustments						
Amortization of excess deferred income tax	(2,682)	(1.72)	(2,612)	(2.00)	(8,607)	(7.67)
U.S. state income taxes (benefits), net of federal effect	2,933	1.88	2,606	1.99	2,414	2.15
Total income taxes	$ 32,085	20.52%	$ 27,114	20.75%	$ 17,297	15.41%

The components of TNMP’s income taxes paid were:

	Year Ended December 31, 2025	2024	2023
		(In thousands)	
U.S. federal	$ 2,579	$ 8,412	$ 13,990
U.S. state			
New Mexico	—	—	—
Texas	4,940	2,609	2,914
Total paid (refunded)	$ 7,519	$ 11,021	$ 16,904

The components of TNMP's net accumulated deferred income tax liability were:

	December 31, 2025	December 31, 2024
	(In thousands)	
Deferred tax assets:		
Regulatory liabilities related to income taxes	$ 17,508	$ 18,221
Other	5,099	4,522
Total deferred tax assets	22,607	22,743
Deferred tax liabilities:		
Depreciation and plant related	(212,168)	(200,709)
Regulatory assets related to income taxes	(8,278)	(8,589)
Loss on reacquired debt	(4,709)	(4,981)
Pension	(4,749)	(4,706)
AMS	(2,816)	(2,709)
Other	(19,262)	(9,156)
Total deferred tax liabilities	(251,982)	(230,850)
Net accumulated deferred income tax liabilities	$ (229,375)	$ (208,107)

The following table reconciles the change in TNMP's net accumulated deferred income tax liability to the deferred income tax included in the Consolidated Statement of Earnings:

	Year Ended December 31, 2025
	(In thousands)
Net change in deferred income tax liability per above table	$ 21,268
Change in tax effects of income tax related regulatory assets and liabilities	(401)
Amortization of excess deferred income tax	(2,682)
Other	(1)
Deferred income tax	$ 18,184

Other Disclosures

The Company is required to recognize only the impact of tax positions that, based on their technical merits, are more likely than not to be sustained upon an audit by the taxing authority. A reconciliation of unrecognized tax benefits is as follows:

	TXNM	PNM	TNMP
		(In thousands)	
Balance at December 31, 2022	$ 15,154	$ 12,201	$ 151
Additions (reductions) based on tax positions related to 2023	(277)	(294)	17
Additions for tax positions of prior years	259	239	20
Balance at December 31, 2023	15,136	12,146	188
Additions based on tax positions related to 2024	19	2	17
Additions (reductions) for tax positions of prior years	(154)	(163)	9
Balance at December 31, 2024	15,001	11,985	214
Additions based on tax positions related to 2025	559	547	12
Additions for tax positions of prior years	82	53	28
Balance at December 31, 2025	$ 15,642	$ 12,585	$ 254

Included in the balance of unrecognized tax benefits at December 31, 2025 are $15.6 million, $12.5 million, and $0.3 million that, if recognized, would affect the effective tax rate for TXNM, PNM, and TNMP. The Company does not anticipate that any unrecognized tax expenses or unrecognized tax benefits will be reduced or settled in 2026.

TXNM, PNM, and TNMP had no estimated interest income or expense related to income taxes for the years ended December 31, 2025, 2024, and 2023. There was no accumulated accrued interest receivable or payable related to income taxes as of December 31, 2025 and 2024.

The Company files a federal consolidated and several consolidated and separate state income tax returns. The tax years prior to 2022 are closed to examination by either federal or state taxing authorities other than Arizona. The tax years prior to 2021 are closed to examination by Arizona taxing authorities. Other tax years are open to examination by federal and state taxing authorities and net operating loss carryforwards are open to examination for the years in which the carryforwards are utilized. At December 31, 2025, the Company has $330.7 million of federal net operating loss carryforwards that expire beginning in 2036 and $130.0 million of federal tax credit carryforwards that expire beginning in 2026. State net operating losses expire beginning in 2038 and vary from federal due to differences between state and federal tax law.

In 2008, fifty percent bonus tax depreciation was enacted as a temporary two-year stimulus measure as part of the Economic Stimulus Act of 2008. Bonus tax depreciation in various forms has been extended since that time, including by the Protecting Americans from Tax Hikes Act of 2015. The 2015 act extended and phased-out bonus tax depreciation through 2019. As discussed above, the Tax Act eliminated bonus depreciation for utilities effective September 28, 2017. However, in 2020 the IRS issued regulations interpreting Tax Act amendments to depreciation provisions of the IRC which allowed the Company to claim a bonus depreciation deduction on certain construction projects placed in service after the third quarter of 2017. As a result of the net operating loss carryforwards for income tax purposes created by bonus depreciation, certain tax carryforwards were not expected to be utilized before their expiration. In addition, as a result of Tax Act changes to the deductibility of officer compensation, certain deferred tax benefits related to compensation are not expected to be realized. The Company has impaired the deferred tax assets for tax carryforwards which are not expected to be utilized and for compensation that is not expected to be deductible.

The Company earns investment tax credits for construction or purchase of eligible property. The Company uses the deferral method of accounting for these investment tax credits. Impairments of tax attributes after reflecting the expiration of carryforwards under applicable tax laws for 2023 through 2025 are as follows:

	TXNM	PNM	TNMP
		(In thousands)	
December 31, 2025:			
Federal tax credit carryforwards	$ 625	$ 194	$ —
Compensation expense	$ (120)	$ (70)	$ (50)
December 31, 2024:			
Federal tax credit carryforwards	$ 131	$ —	$ —
Compensation expense	$ (516)	$ (335)	$ (179)
December 31, 2023:			
Federal tax credit carryforwards	$ 839	$ (427)	$ —
Compensation expense	$ 387	$ 246	$ 140

The tax effect of compensation that is not expected to be deductible and impairments of unexpired tax credits are reflected as a valuation allowance against deferred tax assets. The reserve balances, after reflecting expiration of carryforwards under applicable tax laws, at December 31, 2025 and 2024 are as follows:

	TXNM	PNM	TNMP
		(In thousands)	
December 31, 2025:			
Federal tax credit carryforwards	$ 2,811	$ 194	$ —
Compensation expense	$ 476	$ 324	$ 152
December 31, 2024:			
Federal tax credit carryforwards	$ 2,186	$ —	$ —
Compensation expense	$ 596	$ 394	$ 202

(19) Goodwill

The excess purchase price over the fair value of the assets acquired and the liabilities assumed by TXNM for its 2005 acquisition of TNP was recorded as goodwill and was pushed down to the businesses acquired. In 2007, the TNMP assets that were included in its New Mexico operations, including goodwill, were transferred to PNM. TXNM's reporting units that currently have goodwill are PNM and TNMP. The Company evaluates its goodwill for impairment annually at the reporting unit level or more frequently if circumstances indicate that the goodwill may be impaired. Application of the impairment test requires judgment, including the identification of reporting units, assignment of assets and liabilities to reporting units, and determination of the fair value of each reporting unit.

In certain circumstances an entity may perform a qualitative analysis to conclude that the goodwill of a reporting unit is not impaired. Under a qualitative assessment an entity considers macroeconomic conditions, industry and market considerations, cost factors, overall financial performance, other relevant entity-specific events affecting a reporting unit, as well as whether a sustained decrease (both absolute and relative to its peers) in share price has occurred. An entity considers the extent to which each of the adverse events and circumstances identified could affect the comparison of a reporting unit's fair value with its carrying amount. An entity places more weight on the events and circumstances that most affect a reporting unit's fair value or the carrying amount of its net assets. An entity also considers positive and mitigating events and circumstances that may affect its determination of whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. An entity evaluates, on the basis of the weight of evidence, the significance of all identified events and circumstances in the context of determining whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. A quantitative analysis is not required if, after assessing events and circumstances, an entity determines that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount.

In other circumstances, an entity may perform a quantitative analysis to reach the conclusion regarding impairment with respect to a reporting unit. An entity may choose to perform a quantitative analysis without performing a qualitative analysis and may perform a qualitative analysis for certain reporting units, but a quantitative analysis for others. The first step of the quantitative impairment test requires an entity to compare the fair value of the reporting unit with its carrying value, including goodwill. If as a result of this analysis, the entity concludes there is an indication of impairment in a reporting unit having goodwill, the entity is required to perform the second step of the impairment analysis, determining the amount of goodwill impairment to be recorded. The amount is calculated by comparing the implied fair value of the goodwill to its carrying amount. This exercise would require the entity to allocate the fair value determined in step one to the individual assets and liabilities of the reporting unit. Any remaining fair value would be the implied fair value of goodwill on the testing date. To the extent the recorded amount of goodwill of a reporting unit exceeds the implied fair value determined in step two, an impairment loss would be reflected in results of operations.

TXNM periodically updates its quantitative analysis for both PNM and TNMP. The use of a quantitative approach in a given period is not necessarily an indication that a potential impairment has been identified under a qualitative approach. When TXNM performs a quantitative analysis for PNM or TNMP, a discounted cash flow methodology is primarily used to estimate the fair value of the reporting unit. This analysis requires significant judgments, including estimations of future cash flows, which is dependent on internal forecasts, estimations of long-term growth rates for the business, and determination of appropriate weighted average cost of capital for the reporting unit. Changes in these estimates and assumptions could materially affect the determination of fair value and the conclusion of impairment.

When TXNM performs a qualitative or quantitative analysis for PNM or TNMP, TXNM considers market and macroeconomic factors including changes in growth rates, changes in the WACC, and changes in discount rates. TXNM also evaluates its stock price relative to historical performance, industry peers, and to major market indices, including an evaluation of TXNM's market capitalization relative to the carrying value of its reporting units.

For its annual evaluations performed as of April 1, 2023, TXNM performed a qualitative analysis for both the PNM and TNMP reporting units. In addition to the typical considerations discussed above, the qualitative analysis considered changes in the Company's expectations of future financial performance since the April 1, 2018 quantitative analysis and the previous qualitative analyses through April 1, 2022 performed for PNM, as well as the April 1, 2021 quantitative analysis and the previous qualitative analyses performed for TNMP. This analysis considered Company specific events such as the Merger, potential impacts of legal and regulatory matters discussed in Notes 16 and 17, including potential outcomes in PNM's 2024 Rate Change, PNM's San Juan Abandonment Application, PNM's Four Corners Abandonment Application, PNM's PVNGS Leased Interest

Abandonment Application and other potential impacts of changes in PNM's resource needs based on PNM's 2020 IRP. Based on an evaluation of these and other factors, the Company determined it was not more likely than not that the April 1, 2023 carrying values of PNM and TNMP exceeded their fair value.

For its annual evaluations performed as of April 1, 2024, TXNM performed a quantitative analysis for the PNM reporting unit and a qualitative analysis for the TNMP reporting unit. The quantitative analysis, discussed above, indicated that the fair value of the PNM reporting unit, which has goodwill of $51.6 million, exceeded its carrying value by approximately 54%. The qualitative analysis, in addition to the typical considerations discussed above, considered changes in the Company's expectations of future financial performance since the April 1, 2020 quantitative analysis and the previous qualitative analyses through April 1, 2023, performed for TNMP. This analysis considered events specific to TNMP such as the potential impacts of legal and regulatory matters discussed in Note 16 and Note 17. Based on an evaluation of these and other factors, the Company determined it was not more likely than not that the April 1, 2024 carrying values of PNM and TNMP exceeded their fair value. Since the April 1, 2024 annual evaluation, there have been no events or indications that the fair values of the reporting units with recorded goodwill have decreased below their carrying values.

For its annual evaluations performed as of April 1, 2025, TXNM performed a qualitative analysis for both the PNM and TNMP reporting units. In addition to the typical considerations discussed above, the qualitative analysis considered changes in the Company's expectations of future financial performance since the April 1, 2024, quantitative analysis performed for PNM, as well as the April 1, 2020 quantitative analysis and the previous qualitative analyses through April 1, 2024 performed for TNMP. This analysis considered Company-specific events such as the Merger, potential impacts of legal and regulatory matters discussed in Note 16 and Note 17, including the outcomes in the 2025 Rate Request, PNM's Grid Modernization Plan, and TNMP's System Resiliency Plan. Based on an evaluation of these and other factors, the Company determined it was not more likely than not that the April 1, 2025, carrying values of PNM and TNMP exceeded their fair value.

(20) Related Party Transactions

TXNM, PNM, TNMP, and NMRD are considered related parties, as is PNMR Services Company, a wholly-owned subsidiary of TXNM that provides corporate services to TXNM and its subsidiaries in accordance with shared services agreements. These services are billed at cost on a monthly basis to the business units. In addition, prior to the sale of NMRD, PNM purchased renewable energy from certain NMRD-owned facilities at a fixed price per MWh of energy produced. On February 27, 2024, PNMR Development and AEP OnSite Partners sold their respective interests in NMRD, and the table below reflects transactions with NMRD prior to the sale.

TXNM files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between TXNM and each of its affiliated companies. These agreements provide that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to TXNM. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from TXNM to the extent that TXNM is able to utilize those benefits. See Note 7 for information on intercompany borrowing arrangements. The table below summarizes the nature and amount of related party transactions of TXNM, PNM and TNMP:

	Year Ended December 31,		
	2025	2024	2023
		(In thousands)	
Services billings:			
TXNM to PNM	$ 133,409	$ 132,209	$ 124,321
TXNM to TNMP	53,852	53,166	47,470
PNM to TNMP	311	440	349
TNMP to TXNM	99	114	141
TNMP to PNM	—	497	—
TXNM to NMRD	—	66	333
Renewable energy purchases:			
PNM from NMRD	—	1,523	12,717
Interest billings:			
TXNM to PNM	250	142	23
PNM to TXNM	527	612	582
TXNM to TNMP	215	210	129
Income tax sharing payments:			
TXNM to PNM	13,336	2,351	5,338
PNM to TXNM	—	—	—
TNMP to TXNM	5,169	10,312	15,749

(21) Equity Method Investment

In September 2017, PNMR Development and AEP OnSite Partners created NMRD to pursue the acquisition, development, and ownership of renewable energy generation projects, primarily in the state of New Mexico. PNMR Development and AEP OnSite Partners each had a 50% ownership interest in NMRD. TXNM accounted for its investment in NMRD using the equity method of accounting because TXNM's ownership interest results in significant influence, but not control over NMRD and its operations. During 2024 and 2023 PNMR Development and AEP OnSite Partners each made cash contributions of $12.6 million and $26.3 million to NMRD.

On December 22, 2023, PNMR Development and AEP Onsite reached agreement with Exus New Mexico, LLC, a subsidiary of Exus North America Holdings, LLC, for the sale of NMRD and its subsidiaries, pursuant to a Membership Interest Purchase Agreement, dated December 22, 2023 ("MIPA"). Closing occurred on February 27, 2024, with PNMR Development receiving net proceeds of $117.0 million and recognized an after-tax gain of $4.4 million, which includes the recognition of deferred investment tax credits of $15.7 million.

TXNM presented its share of net earnings from NMRD in other income on the Consolidated Statements of Earnings until the closing of the sale discussed above. Summarized financial information for NMRD is as follows:

	December 31,		
	2025	2024	2023
		(In thousands)	
Operating revenues	$ —	$ 3,204	$ 13,629
Operating expenses	—	3,378	8,228
Net earnings	$ —	$ (174)	$ 5,401

(22) Merger

On May 18, 2025, TXNM, Parent, and Merger Sub, entered into the Merger Agreement, pursuant to which Merger Sub will merge with and into TXNM, with TXNM surviving the Merger as a direct wholly-owned subsidiary of Parent. Parent and Merger Sub are affiliates of Blackstone Infrastructure.

Pursuant to the Merger Agreement, each issued and outstanding share of the common stock of TXNM (other than (i) the issued shares of TXNM common stock that are owned by TXNM, Parent, Merger Sub, or any other wholly-owned subsidiaries of Parent or TXNM, in each case, not held on behalf of third parties, which will be automatically cancelled at the Effective Time and (ii) shares of TXNM common stock outstanding immediately prior to the Effective Time and held by a holder who has not voted in favor of, or consented in writing to, the Merger who is entitled to, and who has demanded, payment for fair value of such shares in accordance with applicable New Mexico law) will, at the Effective Time, be converted into the right to receive $61.25 in cash, without interest.

The proposed Merger has been unanimously approved by the Board, and it was approved by a majority of the holders of outstanding shares of TXNM common stock, as of the applicable record date, at the special meeting held on August 28, 2025. On January 13, 2026, the waiting period under the HSR Act in connection with the Merger expired and on January 23, 2026, the FCC consented to the two transfers of control applications submitted by Parent and TXNM. Consummation of the Merger is subject to the satisfaction or waiver of certain customary conditions, including the absence of any material adverse effect on TXNM, the absence of legal prohibition on the consummation of the Merger (a “Legal Restraint”), and absence of any agreement between Parent or TXNM and the FCC or Antitrust Division of the U.S. Department of Justice prohibiting the Merger, and the receipt of certain required regulatory approvals (including NMPRC and NRC). The Merger Agreement does not contain any financing condition. On August 25, 2025, TXNM filed applications for regulatory approvals to the NMPRC, PUCT, and FERC (Note 17). On February 6, 2026, the PUCT approved a unanimous settlement agreement filed by parties to the merger proceeding filed in December and on February 20, 2026, the FERC approved the proposed Merger. The Merger is currently expected to close in the second half of 2026.

The Merger Agreement may be terminated by each of TXNM and Parent under certain circumstances, including if the Merger is not consummated by the 15-month anniversary of the execution of the Merger Agreement (as extended, the “End Date”), so long as failure of the Merger to consummate on or before the End Date was not due to the breach of the Merger Agreement by such party, subject to an automatic extension of the End Date until December 31, 2026 and an additional three-month extension by mutual agreement of the parties, in each case if all of the conditions to the closing, other than the conditions related to obtaining regulatory approvals or the absence of a Legal Restraint, have been satisfied or waived. The Merger Agreement also provides for other customary termination rights for both Parent and TXNM. The Merger Agreement further provides that, upon termination of the Merger Agreement under certain specified circumstances, TXNM will be required to pay Parent a termination fee of $210.0 million plus certain costs and expenses (“TXNM Termination Fee”). In addition, the Merger Agreement provides that (i) if the Merger Agreement is terminated by either party as a result of a Legal Restraint (solely in connection with required regulatory approvals), (ii) if the Merger Agreement is terminated by either party as a result of the Merger not being consummated by the End Date, (iii) the Merger Agreement is terminated by TXNM as a result of a breach of any representation or warranty or failure to perform by Parent or Merger Sub that is not curable or timely cured or (iv) Parent fails to effect the closing when all closing conditions (other than those that by their nature are to be satisfied at closing) have been satisfied or waived and it is otherwise obligated to do so under the Merger Agreement and it further fails to consummate the closing within two business days after receiving notice from TXNM, then, in any such case, upon termination of the Merger Agreement, Parent will be required to pay TXNM a termination fee of $350.0 million plus certain costs and expenses (the “Parent Termination Fee”).

Parent and Merger Sub have obtained equity and debt financing commitments for the transactions contemplated by the Merger Agreement. Pursuant to an equity commitment letter dated May 18, 2025 (the “Equity Commitment Letter”), Blackstone Infrastructure committed to provide Parent, at the consummation of the Merger, with an equity contribution in the amount set forth therein. In addition, pursuant to debt commitment letters (“Debt Commitment Letters”) delivered to Merger Sub, Royal Bank of Canada, MUFG Bank, Ltd., BNP Paribas, Sumitomo Mitsui Banking Corporation and Canadian Imperial Bank of Commerce, New York Branch have agreed to provide debt financing to Merger Sub following the Closing on the terms and subject to the conditions set forth therein. The equity financing, when funded in accordance with the Equity Commitment Letter together with the debt financing when funded in accordance with the Debt Commitment Letters, will provide an amount that is sufficient to fund the (i) payment of the aggregate per share merger consideration, (ii) repayment, prepayment or discharge of certain obligations of the Company and its subsidiaries that would become due (after giving effect to the Merger) and are intended to be repaid at Closing and (iii) payment of all fees and expenses expected to be incurred at Closing in connection therewith. Additionally, following Closing, Parent and TXNM will have sufficient funds to repay, prepay or discharge certain other debt obligations of TXNM. In addition, Blackstone Infrastructure has executed and delivered a limited guarantee in favor of TXNM (the “Limited Guarantee”), pursuant to which Blackstone Infrastructure has guaranteed the obligations of Parent and Merger Sub to pay the Parent Termination Fee and certain other fees and expenses under the Merger Agreement. The Limited Guarantee is capped at $375.0 million.

Upon consummation of the Merger, the outstanding shares of TXNM common stock will be delisted from the New York Stock Exchange and deregistered under the Exchange Act.

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)	6,914,649,172	6,914,649,172
4	Property Under Capital Leases	125,677,449	125,677,449
5	Plant Purchased or Sold	—	—
6	Completed Construction not Classified	310,057,396	310,057,396
7	Experimental Plant Unclassified	—	—
8	Total (3 thru 7)	7,350,384,017	7,350,384,017
9	Leased to Others	—	—
10	Held for Future Use	24,362,279	24,362,279
11	Construction Work in Progress	370,820,525	370,820,525
12	Acquisition Adjustments	16,779,747	16,779,747
13	Total Utility Plant (8 thru 12)	7,762,346,568	7,762,346,568
14	Accum Prov for Depr, Amort, & Depl	2,409,592,573	2,409,592,573
15	Net Utility Plant (13 less 14)	5,352,753,995	5,352,753,995
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,409,592,573	2,409,592,573
19	Amort & Depl of Producing Nat Gas Land/Land Right	—	
20	Amort of Underground Storage Land/Land Rights	—	
21	Amort of Other Utility Plant	—	—
22	Total In Service (18 thru 21)	2,409,592,573	2,409,592,573
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)	2,409,592,573	2,409,592,573

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	4/17/2026	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
—	—	—	—	—	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

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication	446,109	3,229,006
3	Nuclear Materials	33,054,639	12,823,448
4	Allowance for Funds Used during Construction	6,901,367	2,924,743
5	(Other Overhead Construction Costs, provide details in footnote)	—	—
6	SUBTOTAL (Total 2 thru 5)	40,402,115	—
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	657,172	—
9	In Reactor (120.3)	59,739,890	—
10	SUBTOTAL (Total 8 & 9)	60,397,062	—
11	Spent Nuclear Fuel (120.4)	—	—
12	Nuclear Fuel Under Capital Leases (120.6)	—	—
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	28,245,381	—
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	72,553,796	—
15	Estimated net Salvage Value of Nuclear Materials in line 9	—	
16	Estimated net Salvage Value of Nuclear Materials in line 11	—	
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing	—	
18	Nuclear Materials held for Sale (157)	—	
19	Uranium	—	—
20	Plutonium	—	—
21	Other (provide details in footnote):	—	—
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)	—	—

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
	2,496,083	1,179,032	2
	9,009,737	36,868,350	3
	2,140,775	7,685,335	4
	—	—	5
	—	45,732,717	6
			7
—	—	657,172	8
—	1,480,076	58,259,814	9
—	1,480,076	58,916,986	10
—	—	—	11
—	—	—	12
(14,834,497)	15,126,671	27,953,207	13
—	—	76,696,496	14
		—	15
		—	16
		—	17
		—	18
—	—	—	19
—	—	—	20
—	—	—	21
—	—	—	22

FOOTNOTE DATA

Page 203, Row 9, Column (e)

A.	Unit reload dollars transferred from fabrication (Line 2) to in stock (Line 8)	$2,496,083
	Unit reload dollars transferred from nuclear materials (Line 3) to in stock (Line 8)	9,009,737
	Unit reload dollars transferred from AFUDC (Line 4) to in stock (Line 8)	2,140,775
		$13,646,595
B.	In stock account (Line 8) to in reactor account (Line 9)	($13,646,596)
	Assemblies transferred from in reactor account (Line 9) to accum prov for amort (Line 13)	15,126,671
		$1,480,075
C.	Cost of assemblies transferred from in reactor account (Line 9) to accumulated provision for amortization account (Line 13)	$15,126,671

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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	74,269,669	2,656,896
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	74,269,669	2,656,896
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	644,446	—
9	(311) Structures and Improvements	33,966,860	104,594
10	(312) Boiler Plant Equipment	301,296,140	13,942,143
11	(313) Engines and Engine-Driven Generators	—	
12	(314) Turbogenerator Units	65,645,528	11,743,105
13	(315) Accessory Electric Equipment	24,960,163	882,338
13.1	(315.1) Computer Hardware	—	—
13.2	(315.2) Computer Software	—	15,909
13.3	(315.3) Communication Equipment	—	—
14	(316) Misc. Power Plant Equipment	34,252,060	1,687,405
15	(317) Asset Retirement Costs for Steam Production	7,441,459	2,808,017
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	468,206,656	31,183,511
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	484,444	—
19	(321) Structures and Improvements	200,991,560	4,382,941
20	(322) Rector Plant Equipment	324,041,277	9,872,763
21	(323) Turbogenerator Units	110,938,086	2,331,880
22	(324) Accessory Electric Equipment	55,507,456	819,973
22.1	(324.1) Computer Hardware	—	—
22.2	(324.2) Computer Software	—	7,870,459
22.3	(324.3) Communication Equipment	—	—
23	(325) Misc. Power Plant Equipment	68,844,965	909,827
24	(326) Asset Retirement Costs for Nuclear Production	12,831,931	—
25	TOTAL Nuclear Production Plant (Enter Total of Lines 18 thru 24)	773,639,719	26,187,843
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)	—	—

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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
1,714	—	(76,924,851)	—		4
1,714	—	(76,924,851)	—		5
					6
					7
—		—	644,446		8
—	—	—	34,071,454		9
3,984,320	—	—	311,253,963		10
—	—		—		11
1,177,641	—	—	76,210,992		12
294,705	—	—	25,547,796		13
—	—	—	—		13.1
361,174	—	1,707,494	1,362,229		13.2
—	—	322,679	322,679		13.3
349,564	—	—	35,589,901		14
—		—	10,249,476		15
6,167,404	—	2,030,173	495,252,936		16
					17
—	—	—	484,444		18
851,977	—	—	204,522,524		19
927,313	—	—	332,986,727		20
919,027	—	—	112,350,939		21
98,708	—	—	56,228,721		22
—	—	—	—		22.1
2,361,006	—	6,673,216	12,182,669		22.2
—	—	408,257	408,257		22.3
119,828	—	—	69,634,964		23
—	—	—	12,831,931		24
5,277,859	—	7,081,473	801,631,176		25
					26
—	—	—	—		27
—	—	—	—		28
—	—	—	—		29
—	—	—	—		30
—	—	—	—		31
—	—	—	—		31.1
—	—	—	—		31.2
—	—	—	—		31.3
—	—	—	—		32
—	—	—	—		33
—	—	—	—		34
—	—	—	—		35

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
35.1	D. Solar Production Plant		
35.2	(338.1) Land and Land Rights	—	—
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	—	—
35.9	(338.8) Other Accessory Electrical Equipment	—	—
35.10	(338.9) Computer Hardware	—	51,760
35.11	(338.10) Computer Software	—	—
35.12	(338.11) Communication Equipment	—	280,600
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)	—	332,360
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	—	—
36	D. Other Production Plant		
37	(340) Land and Land Rights	20,080,146	—
38	(341) Structures and Improvements	94,167,674	419,020
39	(342) Fuel Holders, Products and Accessories	113,185,378	7,338,051
40	(343) Prime Movers	—	—
41	(344) Generators	531,587,113	9,531,619
42	(345) Accessory Electric Equipment	56,826,798	398,959
42.1	(345.1) Computer Hardware	—	—
42.2	(345.2) Computer Software	—	(43,324)
42.3	(345.3) Communication Equipment	—	(230)
43	(346) Misc. Power Plant Equipment	42,126,492	10,199,464
44	(347) Asset Retirement Costs for Other Production	3,590,445	3,418,128
44.1	(348) Energy Storage Equipment - Production	29,540,372	423
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	891,104,418	31,262,110
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, 35.15, 35.32,	2,132,950,793	88,965,824

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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.
					35.1
—	—	11,040,948	11,040,948		35.2
—	—	268,299	268,299		35.3
—	—	277,545,592	277,545,592		35.5
—	—	8,264,812	8,264,812		35.6
—	—	—	—		35.7
—	—	—	—		35.8
—	—	33,903,100	33,903,100		35.9
—	—	—	51,760		35.10
—	—	—	—		35.11
—	—	356,977	637,577		35.12
—	—	5,228,178	5,228,178		35.13
—	—	—	—		35.14
—	—	336,607,906	336,940,266		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
—	—	(11,040,948)	9,039,198		37
552,276	—	(268,299)	93,766,119		38
156,801	—	—	120,366,628		39
—	—	—	—		40
2,227,197	—	(277,545,592)	261,345,943		41
106,148	—	(32,994,052)	24,125,557		42
539,793	—	593,678	53,885		42.1
569,748	—	674,003	60,931		42.2
—	—	39,092	38,862		42.3
976,838	—	(5,228,178)	46,120,940		43
—	—	—	7,008,573		44
—	—	(29,540,795)	—		44.1
5,128,801	—	(355,311,091)	561,926,636		45
16,574,064	—	(9,591,539)	2,195,751,014		46

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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	133,876,906	(57,759)
48.2	(351.1) Computer Hardware	—	12,495,565
48.3	(351.2) Computer Software	—	1,613,937
48.4	(351.3) Communication Equipment	—	11,001,001
49	(352) Structures and Improvements	208,231,506	37,603,632
50	(353) Station Equipment	930,695,909	55,848,184
51	(354) Towers and Fixtures	72,432,427	(605,217)
52	(355) Poles and Fixtures	535,580,133	18,097,041
53	(356) Overhead Conductors and Devices	221,344,571	9,818,379
54	(357) Underground Conduit	185,394	—
55	(358) Underground Conductors and Devices	—	—
56	(359) Roads and Trails	9,800,591	—
57	(359.1) Asset Retirement Costs for Transmission Plant	—	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,112,147,437	145,814,763
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	12,468,303	1,419,563
61	(361) Structures and Improvements	43,143,473	30,807,315
62	(362) Station Equipment	307,396,292	15,606,616
63	(363) Storage Battery Equipment	2,824,228	
63.1	(363.1) Computer Hardware	—	3,865,246
63.2	(363.2) Computer Software	—	20,785,786
63.3	(363.3) Communication Equipment	—	7,583,734
64	(364) Poles, Towers, and Fixtures	388,122,200	58,210,720
65	(365) Overhead Conductors and Devices	275,834,120	21,018,889
66	(366) Underground Conduit	172,779,187	20,209,380
67	(367) Underground Conductors and Devices	410,816,563	56,069,648
68	(368) Line Transformers	271,670,538	15,981,512
69	(369) Services	253,457,773	23,422,802
70	(370) Meters	63,283,276	4,596,089
71	(371) Installations on Customer Premises	9,458,882	—
72	(372) Leased Property on Customer Premises	—	—
73	(373) Street Lighting and Signal Systems	27,260,638	2,990,914
74	(374) Asset Retirement Costs for Distribution Plant	14,202	—
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,238,529,675	282,568,214
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights	—	—
78	(381) Structure and Improvements	—	—
79	(382) Computer Hardware	—	—
80	(383) Computer Software	—	—
81	(384) Communication Equipment	—	—
82	(385) Miscellaneous Regional Transmission and Market Operation	—	—
83	(386) Asset Retirement Costs for Regional Transmission and Market	—	—
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru	—	—
84.1	6. ENERGY STORAGE PLANT		
84.2	(387.1) Land and Land Rights	—	—
84.3	(387.2) Structures and Improvements	—	667,798
84.4	(387.3) Energy Storage Equipment	—	(9,334,224)
84.6	(387.5) Collector System	—	4,827,171
84.7	(387.6) Generator Step-up Transformers (GSU)	—	1,712,696
84.8	(387.7) Inverters	—	—
84.9	(387.8) Computer Hardware	—	—
84.10	(387.9) Computer Software	—	605,006
84.11	(387.10) Communication Equipment	—	545,603
84.12	(387.11) Miscellaneous Energy Storage Equipment	—	1,678,587
84.13	(387.12) Asset Retirement Costs for Energy Storage	—	—
84.14	TOTAL Energy Storage Plant (Total lines 84.2 thru 84.13)	—	702,637
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	1,937,568	—

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) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
	0				47
—	—	(22,744)	133,796,403		48
5,903,055	—	11,744,857	18,337,367		48.2
1,280,619	—	8,406,524	8,739,842		48.3
897,169	—	36,617,189	46,721,021		48.4
115,737	—	—	245,719,401		49
12,476,710	—	(712)	974,066,671		50
215,844	—	(6,212,608)	65,398,758		51
1,781,561	—	4,480,741	556,376,354		52
283,350	—	707,928	231,587,528		53
—	—	—	185,394		54
—	—		—		55
—	—	—	9,800,591		56
—			—		57
22,954,045	—	55,721,175	2,290,729,330		58
					59
—	—	(2,020,109)	11,867,757		60
98,946	—	—	73,851,842		61
2,819,345	—	(909,048)	319,274,515		62
		(2,824,228)	—		63
148,273	—	2,677,248	6,394,221		63.1
1,429,592	—	31,235,838	50,592,032		63.2
90,716	—	10,907,200	18,400,218		63.3
3,656,149	—	(2,634,336)	440,042,435		64
1,610,861	—	(5,059,559)	290,182,589		65
450,555	—	(518,934)	192,019,078		66
2,131,855	—	(1,105,862)	463,648,494		67
1,755,592	—	—	285,896,458		68
465,818	—	—	276,414,757		69
1,365,957	—	—	66,513,408		70
—	—	—	9,458,882		71
—	—	—	—		72
294,511	—	—	29,957,041		73
14,202	—	—	—		74
16,332,372	—	29,748,210	2,534,513,727		75
					76
—	—	—	—		77
—	—	—	—		78
—	—	—	—		79
—	—	—	—		80
—	—	—	—		81
—	—	—	—		82
—	—	—	—		83
—	—	—	—		84
					84.1
—	—	—	—		84.2
—	—	—	667,798		84.3
—	—	28,809,909	19,475,685		84.4
—	—	—	4,827,171		84.6
—	—	—	1,712,696		84.7
—	—	—	—		84.8
—	—	—	—		84.9
—	—	—	605,006		84.1
—	—	—	545,603		84.11
—	—	3,555,114	5,233,701		84.1
—	—	—	—		84.1
—	—	32,365,023	33,067,660		84.1
					85
—	—	—	1,937,568		86

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
87	(390) Structures and Improvements	84,454,072	2,170,832
88	(391) Office Furniture and Equipment	24,421,578	290,990
89	(392) Transportation Equipment	16,827,956	964,985
90	(393) Stores Equipment	97,940	—
91	(394) Tools, Shop and Garage Equipment	19,329,327	1,294,942
92	(395) Laboratory Equipment	1,902,383	—
93	(396) Power Operated Equipment	7,014,696	307,028
94	(397) Communication Equipment	48,352,536	298,860
94.1	(397.1) Computer Hardware	—	520,589
94.2	(397.2) Computer Software	—	1,619,278
94.3	(397.3) Communication Equipment	—	—
95	(398) Miscellaneous Equipment	1,778,439	—
96	SUBTOTAL (Enter Total of lines 86 thru 95)	206,116,495	7,467,504
97	(399) Other Tangible Property	—	—
98	(399.1) Asset Retirement Costs for General Plant	19,473	—
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	206,135,968	7,467,504
100	TOTAL (Accounts 101 and 106)	6,764,033,542	528,175,838
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)	6,764,033,542	528,175,838

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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.
517,380	—	—	86,107,524		87
1,367,352	—	(18,171,338)	5,173,878		88
54,714	—	—	17,738,227		89
—	—	—	97,940		90
308,879	—	—	20,315,390		91
1,696,118	—	—	206,265		92
—	—	—	7,321,724		93
—	—	(48,651,396)	—		94
1,299,643	—	3,155,555	2,376,501		94.1
2,275,146	—	28,227,776	27,571,908		94.2
—	—	—	—		94.3
—	—	—	1,778,439		95
7,519,232	—	(35,439,403)	170,625,364		96
—	—	—	—		97
—	—	—	19,473		98
7,519,232	—	(35,439,403)	170,644,837		99
63,381,427	—	(4,121,385)	7,224,706,568		100
—	—	—	—		101
—	—	—	—		102
—	—	—	—		103
63,381,427	—	(4,121,385)	7,224,706,568		104

Page 205, 209, and 211, Rows 20,48,87,89, Column (g)

At December 31, 2025, total Electric Plant in Service Excludes Property Under Capital Lease of $125,677,449.

Pages 205, 207, and 209, Rows 4, 13.2, 13.3, 22.2, 22.3, 35.2-35.13, 37-44.1, 48.2-48.2, 63.1-63.3, 88, 94-94.2, and 96, Column (f)

The 2025 Implementation of FERC Order 898 resulted in the transfer of $512,363,536 of asset between certain utility accounts as follows:

Reform Description	*Plant Description*	*Account*	*Transfer From*	*Transfer to*
Functionalized Software	Intangible	(303) Miscellaneous Intangible Plant	(76,924,850)	
	Steam Production	(315.2) Computer Software		1,707,494
	Nuclear Production	(324.2) Computer Software		6,673,216
	Other Production	(345.2) Computer Software		674,003
	Transmission	(351.2) Computer Software		8,406,524
	Distribution	(363.2) Computer Software		31,235,838
	General	(397.2) Computer Software		28,227,776
Functionalized Hardware	General Plant	(391) Office Furniture and Equipment	(18,171,338)	
	Other Production	(345.1) Computer Hardware		593,678
	Transmission	(351.1) Computer Hardware		11,744,857
	Distribution	(363.1) Computer Hardware		2,677,248
	General	(397.1) Computer Hardware		3,155,555
Functionalized Communication Equipment	General Plant	(397) Communication Equipment	(48,651,395)	
	Steam Production	(315.3) Communication Equipment		322,679
	Nuclear Production	(324.3) Communication Equipment		408,257
	Solar Production	(338.11) Communication Equipment		356,977
	Other Production	(345.3) Communication Equipment		39,092
	Transmission	(351.3) Communication Equipment		36,617,189
	Distribution	(363.3) Communication Equipment		10,907,200
Energy Storage	Other Production	(348) Energy Storage Equipment - Production	(29,540,795)	
	Distribution	(363) Storage Battery Equipment	(2,824,228)	
	Energy Storage	(387.3) Energy Storage Equipment		28,809,909
	Energy Storage	(387.11) Misc Energy Storage Equipment		3,555,114
Solar Production Distribution Collector Systems	Distribution	(362) Station Equipment	(909,048)	
	Distribution	(341) Poles, Towers and Fixtures	(1,554,219)	
	Distribution	(365) Overhead Conductors and Devices	(5,652,400)	
	Distribution	(366) Underground Conduit	(302,955)	
	Distribution	(367) Underground Conductors and Devices	(755,238)	
	Solar Production	(338.5) Collector system		8,264,812
	Solar Production	(338.12) Miscellaneous power plant equipment		909,048
Solar Production Plant Generation	Other Production	(340) Land and Land Rights	(11,040,948)	
	Other Production	(341) Structures and improvements	(268,299)	
	Other Production	(344) Generators	(277,545,592)	
	Other Production	(345) Accessory Electric Equipment	(32,994,052)	
	Other Production	(346) Misc Power Plant Equipment	(5,228,178)	
	Solar Production	(338.1) Land and Land Rights		11,040,948
	Solar Production	(338.2) Structures and improvements		268,299
	Solar Production	(338.4) Solar panels		277,545,592
	Solar Production	(338.8) Other accessory electrical equipment		32,994,052
	Solar Production	(338.12) Miscellaneous power plant equipment		5,228,178
			$(512,363,535)	$512,363,535

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	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 of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Claremont Station, Bernalillo County, NM	12/31/2025		1,431,700
3	Sandia Science&Tech Park, Bernalillo County, NM	10/22/20		1,240,830
4	San Juan Common Land, San Juan County, NM	12/31/22		1,080,477
5	North Albuquerque Acres, Bernalillo County, NM	12/31/25		611,153
6	La Cueva Substation Site, Bernalillo County, NM	2/28/14		530,921
7	Rio Rancho-Pachman ROW, Sandoval County, NM	09/28/07		319,858
8	Prager Station - Albuquerque, NM	12/31/94		311,280
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Other Land and Rights<$250k (7 items)			474,456
23				
24	Other Station Equipment and Improvements:			
25	Sandia Station, Bernalillo County, NM	12/31/24		7,053,690
26	West Mesa Station, Bernalillo County, NM	12/31/24		9,214,817
27				
28	Other Transmission Lines:			
29	Huning Ranch-Los Morros, Valencia County, NM	3/31/2025		2,093,097
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			24,362,279

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	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)
1	001 Line Extensions - Residential	8,243,366
2	002 Line Extensions - Commercial	4,904,196
3	004 Line Extensions - Misc.	182,940
4	005 Lighting	878,544
5	006 Distr. Remove & Replace	6,729,299
6	007 Distr. System Improvements	8,527,043
7	008 Services	824,594
8	009 Transformers	772,042
9	016 Cable Replacement Program 2023-2024	590,437
10	016 Cable Replacement Program 2024-2025	1,095,360
11	016 Caja Del Rio 13 Backbone Upgrade	494,655
12	016 TIJE12 Feeder Rebuild	2,137,140
13	017 Albuquerque Pure Project	340,696
14	017 Deming & Gold Substations	922,294
15	017 Dist Struc Replace and Upgrade 2024	208,001
16	017 FOMA13 Feeder Rebuild	2,021,234
17	017 Silver City Pure Project	136,858
18	018 Hawkins Substation	1,960,523
19	019 Overlook Distribution Rebuild	1,801,169
20	019 Smart Devi Replace and Upgrade 2024	374,569
21	020 Four Hills 13 to Lawrence 14 Feeder	234,434
22	020 Tularosa 13 Ph Load Bal-Voltage Reg	150,304
23	021 Misc 46kv Line	199,026
24	021 Open Wire Secondary Upgrade 2024-20	441,180
25	022 Distribution Looping 2024-2025	2,476,339
26	022 Mejia 14 to SantaFeEstates Line Ext	135,206
27	023 Gila National Forest CO1	492,655
28	025 Prosperity Substation	908,460
29	026 ELCE12 Feeder Laterals Rebuild	3,385,483
30	027 COLI13 Feeder Rebuild Phase 2	899,558
31	029 Outage Contingency Plan Impr-WFF	517,526
32	035 LSCH12 Feeder Rebuild	795,880
33	036 Van Buren Substation Metering	322,374
34	044 Girard Substation	754,626
35	045 Montano Substation	243,599
36	052 Palomas Station-Distribution	5,691,563
37	053 Distribution Relay Upgrades	7,948,366
38	053 Morris Substation	1,916,569
39	055 33.6MVA Pwr Xfmr Critical Sp 2024	4,273,749
40	056 33.6MVA Pwr Xfmr Critical Sp 2025	13,169,981
41	056 NM Ops Long Lead Equip Blanket CO1	11,044,073
42	058 ISLE12 Feeder Rebuild	1,088,722
43	058 Menaul Substation	1,172,357
44	059 Substation Equipment Replacements B	1,250,746
45	061 ANPP Transmission blanket	2,757,389
46	062 SW NM Transmission Blanket	5,297,512
47	070 Gila National Forest Co02	177,617
48	070 Misc. Station Improvements	101,109
49	071 Asset Health Monitoring_Event Rptg	209,309
50	071 Misc. Transmission Blanket	299,550

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	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)
51	071 Tribal Fiber-WFF	119,379
52	072 EPE EP Line Relay Upgrade	430,827
53	072 New Sandia 115 kV Control House	2,058,708
54	073 Reeves-Embudo 115kV Rebuild	1,058,087
55	073 System Equipment Upgrade-WFF	252,541
56	073 WFF-Reconfig Tap Sub Unit 2	1,529,031
57	074 Sandia Battery Storage 60MW-CO2	388,643
58	076 Guadalupe SVC Backup Generator	661,852
59	077 Switch Stations Replacements IA	1,447,676
60	079 Relay IA	530,210
61	080 Transm Comm Improvement 2021-2025	387,526
62	087 Aspen Substation	936,263
63	089 Pajarito-Rio Puerco 345kV ROW	654,227
64	090 NM Ops Long Lead Equipment Blanket	14,980,772
65	092 Norton-Hernandez 115kV Rebuild	818,692
66	093 Palomas Station-Transmission	3,518,149
67	097 Belen-Sun Ranch 115kV Rebuild	1,287,188
68	098 Person-Kirtland Switching 115kV Reb	1,489,684
69	099 Los Lunas Capacity Expansion Phase4	987,156
70	162 La Luz Spare GSU Transformer	874,391
71	174 Afton Non Outage Plant Capital 2024	122,087
72	182 Sandia Battery Storage 60MW	88,831,062
73	190 Four Corners Facility Improvements	6,075,847
74	191 Four Corners Facility - Switchyard	197,461
75	192 Four Corners Facility Improvements	246,339
76	234 PV common	15,232,330
77	234 PV U1	799,791
78	234 PV U2	2,036,036
79	234 PV U3	10,804,584
80	234 PV water reclamation	1,908,707
81	280 FERC 881	254,616
82	319 Gen Svcs Bldg Maint Blanket-Distr	387,550
83	340 ABQ Metro 2010 Tools & Equipment	112,208
84	016 Cable Replacement Program 2025-2026	3,805,532
85	017 Project Array	869,634
86	017 Sub-Transmission Recloser Install	602,273
87	018 Switchgear Replace and Upgrade 2025	238,574
88	019 Smart Devi Replace and Upgrade 2025	728,556
89	019 Rodeo Substation Rebuild CO1	3,366,034
90	020 Deming Streetlight Upgrades	703,157
91	020 Valencia Substation Rebuild	3,783,145
92	020 El Dorado 12 Phase 2 Feeder Rebuild	1,938,190
93	021 Open Wire Secondary Upgrade 2025-20	822,988
94	022 Distribution Looping 2025-2026	1,506,544
95	023 Project Oppidan	2,237,205
96	023 4th Street and St Mary's Way	388,152
97	023 Angel Rd - CRP 23-24	292,044
98	024 Sandia 46kV Breaker Replacement	1,226,238
99	028 Mejia 115kV Transformer LTC Failure	124,974
100	030 ELDO12 Feeder Rebuild	133,836

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
101	032 Sandia 46kV Relay Replacement	3,498,896
102	036 Distribution HFA Feeder Relay Rplc	576,214
103	043 Zia 46kV Relay Replacement	2,250,769
104	044 WF Enhanced Sit Awareness Co1	794,650
105	052 HFA Pole Rplc SilverCity/Ruidoso	258,714
106	052 Central Osmose Pole Replacements	222,987
107	053 Grid Mod - AMI (Advcd Mtrg Infrstr)	9,380,018
108	053 STPE13 Feeder Rebuild	6,419,076
109	053 Northern Osmose Pole Replacements	637,098
110	054 Wildfire Mitigation 2025-2026	1,084,641
111	070 RTU Program	628,980
112	071 Star Light Interconection Expansion	629,953
113	072 Failed Sta Equip Replcmt Progm 2025	999,000
114	074 Transmission Pole Replcmt Prog 2025	510,298
115	076 TPL1 P5 Relay Upgrades	143,893
116	076 San Juan Stn Switchgear Replacement	496,570
117	094 Valencia Substation Rebuild - Trans	2,308,216
118	099 Los Lunas Capacity Expansion Phse 5	9,689,435
119	164 Afton ST Generator Exciter Rewind	357,384
120	166 La Luz Mark VI E Turbine Controls	588,745
121	167 La Luz Balance of Plant Controls	285,749
122	185 Sunbelt Solar and Storage Facility	6,742,830
123	280 Grid Mod - Customer Info and Analyt	1,939,699
124	283 Community Solar 2025 Cust Consent	120,868
125	024 Camino Sin Pasada - CRP2324	401,094
126	030 CORNELL 14 - Feeder Backbone Rebuil	2,148,058
127	031 Morris 12 Feeder Rebuild	1,355,714
128	052 Mesa del Sol Infrastructure CO1	3,400,114
129	057 Westpointe Substation-DIST	3,435,190
130	075 WF Enhanced Sit Awareness Co2	134,887
131	090 Rio Puerco-Sandia Longlead Breakers	3,114,267
132	090 Zia Substation Rebuild CO2	110,615
133	093 Zia and MD1 Control House Replcmt	1,438,133
134	096 Mesa del Sol Infrastructure CO2	260,356
135	097 Westpointe Substation-TRN	1,295,408
136	160 Luna Capital Improvements 2025	126,344
137	169 Reeves U3 Generator Exciter Contrlr	318,746
138	170 Luna Capital Planned Outage 2025	880,429
139	171 Luna GT 2 GSU Transformer Replaceme	1,928,302
140	280 Enterprise Investment Optimization	3,802,514
141	281 Comm Improvements Software	261,471
142	282 Port Opt Copperleaf 2025	3,575,766
143	305 WPM Plumbing Improvement	125,281
144	Other Projects less than $100,000	(3,543,765)
145		
146		
147		
148		
149		
150		
151		
152		
153		
154	Total	370,820,525

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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	2,251,210,719	2,251,210,719	—	—
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	206,700,423	206,700,423	—	
4	(403.1) Depreciation Expense for Asset Retirement Costs	619,089	619,089	—	—
5	(413) Exp. of Elec. Plt. Leas. to Others	—			—
6	Transportation Expenses-Clearing	798,911	798,911		
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)	208,118,423	208,118,423	—	—
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(63,365,506)	(63,365,506)	—	—
13	Cost of Removal	(29,899,730)	(29,899,730)	—	—
14	Salvage (Credit)	3,591,138	3,591,138	—	—
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(89,674,098)	(89,674,098)	—	—
16	Other Debit or Cr. Items (Describe, details in footnote):	39,951,731	39,951,731	—	—
17					
18	Book Cost or Asset Retirement Costs Retired	(14,202)	(14,202)	—	—
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,409,592,573	2,409,592,573	—	—
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	153,480,269	153,480,269	—	—
21	Nuclear Production	421,248,751	421,248,751	—	—
22	Hydraulic Production-Conventional	—	—	—	—
23	Hydraulic Production-Pumped Storage	—	—	—	—
23.1	Solar Production	118,631,374	118,631,374	—	—
23.2	Wind Production	—	—	—	—
23.3	Other Renewable Production	—	—	—	—
24	Other Production	208,115,972	208,115,972	—	—
25	Transmission	579,010,515	579,010,515	—	—
26	Distribution	836,694,277	836,694,277	—	—
27	Regional Transmission and Market Operation	—	—	—	—
27.1	Energy Storage	6,082,691	6,082,691	—	—
28	General	86,328,724	86,328,724	—	—
29	TOTAL (Enter Total of lines 20 thru 28)	2,409,592,573	2,409,592,573	—	—

FOOTNOTE DATA

Page 219, Row 16, Column (c)

	December 31, 2025
FERC 898 Reclass	$ 31,317,896
Change in RWIP	7,575,796
Four Corner Power Plant Write-down	794,445
Four Corners SCR Reduction	418,476
Grid Mod Depreciation Reclass to Reg Asset	165,016
Gain on Disposition of Assets	(319,898)
Total Other Debit or Credit Items	$ 39,951,731

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

FOOTNOTE DATA

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)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	ETBC I:	11/30/2023		—
2	Investment in			1,724,623
3				
4				
5				
6				
7				
8				
9				
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41				
42	Total Cost of Account 123.1		TOTAL	1,724,623

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

FOOTNOTE DATA

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
	—	1,724,623	—	2
				3
				4
				5
				6
				7
				8
				9
				10
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				36
				37
				38
				39
				40
				41
—	—	1,724,623	—	42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	1,095,055	1,090,377	Electric
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)	79,591,207	81,178,645	Electric
6	Assigned to - Operations and Maintenance	—	—	
7	Production Plant (Estimated)	28,974,111	30,651,937	Electric
8	Transmission Plant (Estimated)	26,020,403	26,703,738	Electric
9	Distribution Plant (Estimated)	5,438,182	4,637,187	Electric
10	Regional Transmission and Market Operation Plant (Estimated)	—	—	
11	Assigned to - Other (provide details in footnote)	246,413	164,663	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	140,270,316	143,336,170	
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)	141,365,371	144,426,547	

FOOTNOTE DATA

Page 227, Row 11, Column (c)

Represents Non capital/O&M portion of electric inventory

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	WIRES-TO-WIRES - PATTERN - BOLO	11,707	253		
3	Clearway TSR Study	571	253	78,313	253
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20	Total	12,278		78,313	
21	**Generation Studies**				
22	DISIS #12 PNM GEN PINON NORTH 280MW	2,403	253	2,403	253
23	DISIS #12 PNM GEN PINON 80MW	31,362	253	31,362	253
24	IA-PNM-2021-13			59,737	253
25	IA-PNM-2022-01	75,853	253		
26	IA-PNM-2022-02			140,490	253
27	IA-PNM-2022-03	16,765	253		
28	IA-PNM-2022-11	93,138	253	93,138	253
29	IA-PNM-2022-10	78,253	253	78,253	253
30	IA-PNM-2023-01	41,358	253		
31	IA-PNM-2023-08	22,899	253		
32	IA-PNM-2023-06	21,214	253		
33	IA-PNM-2023-11	30,881	253		
34	IA-PNM-2023-10	21,193	253		
35	IA-PNM-2023-07	22,642	253		
36	IA-PNM-2023-03	18,735	253		
37	IA-PNM-2023-04	18,246	253		
38	IA-PNM-2023-05	20,553	253		
39	IA-PNM-2023-02	20,553	253		
40	NEXTERA WINDY LANE	97,957	253	97,957	253

Transmission Service and Generation Interconnection Study Costs (continued)					

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)
	Generation Studies				
41	IA-PNM-2023-14	18,971	253		
42	IA-PNM-2023-15	18,567	253		
43	IA-PNM-2023-23		253	22,704	253
44	IA-PNM-2023-18	16,525	253		
45	ROUTE 66 SOLAR ENERGY MMA			6,083	253
46	DISIS #17 AURORA SOLAR LLC-KING	58	253		
47	IA-PNM-2023-30	21,063	253		
48	IA-PNM-2024-01	16,022	253		
49	IA-PNM-2024-02	16,296	253		
50	IA-PNM-2024-04	19,497	253		
51	RIO SOL	1,323	253		
52	2025 SGIP PRE-APP	1,867	253	1,567	253
53	DISIS #19 AE Renewable Development	25,040	253		
54	DISIS #19 AE Renewable Development	18,661	253		
55	DISIS Cluster 19 Clenera - Atrisco	31,009	253		
56	DISIS #19 Aurora Solar Phase II 150	16,248	253		
57	Cluster 19 Pattern - Palomas II Win	20,424	253		
58	Cluster 19 Pattern - Palomas Wind 4	26,506	253		
59	Cluster 19 Pattern - Pattern - Hidd	19,046	253		
60	Cluster 19 Jupiter Power - Belen En	15,004	253		
61	DISIS #19 Aypa Power - Hidden Mount	28,233	253		
62	DISIS #19 Berrendo Energy - Isaba W			155,913	253
63	Marquez Tap BESS 115MW	16,881	253		
64	DISIS #19 Orion Renewable Energy	30,576	253		
65	DISIS #19 Allium Renewable Energy	20,862	253		
66	DISIS #19 Allium Renewable Energy-	16,997	253		
67	DISIS #19 AES Clean Energy			8,681	253
68	DISIS #19 PNM Generation	29,255	253	29,255	253
69	DISIS #12 - Bernalillo Sollar MMR	32,111	253	32,111	253
70	DISIS #14 Old Route 66 MMR	20,342	253	18,368	253
71	DISIS #8 - Amrep MMR	1,701	253		
72	DISIS #14 - NMRD Huning Solar MMR	739	253		
73	DISIS #8 - La Bajada MMR	739	253		
74	DISIS #14 - NMRD Belen Solar MMR	13,448	253	7,907	253
75	DISIS #10 - DESRI Rockmont Developm	49,415	253	49,415	253
76	Red Mesa- MMR	7,439	253		253
77	BRITTON MMR	7,793	253	7,793	253
78	ENCINO KING 3 MMR	27,021	253	27,021	253
79	TAG MMR	16,165	253	16,165	253
80	PATTERN NON-TARIFF SIS	33,840	253	1,174	253

Transmission Service and Generation Interconnection Study Costs (continued)

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)
	Generation Studies				
81	Lightning Dock Geothermal II - B	2,174	253	71	253
82	Lightning Dock Geothermal II - A	2,237	253	392,788	253
83	PSEUDO TIE AGREEMENT-TRI-STATE	71	253	71	253
84	ARROYO SOLAR NON-TARIFF SIS	2,008	253	74,530	253
85	PATTERN-BOLO-TIE STUDY			392,788	253
86					
87					
88					
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108					
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110					
111					
112					
113					
114					
115					
116					
117					
118					
119	Total	1,296,179		1,747,745	
120	Grand Total	1,308,457		1,826,058	

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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/ Year)
				Written off During the Quarter/ Year	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Income Tax	74,924,925	3,177,250	282/283	1,222,565	76,879,610
2	PBC Refinancing Hedge - Jul 2038	8,014,644	—	425	844,446	7,170,198
3	UG Rate Rider 22-00276-UT	3,545,751	—	131	1,978,909	1,566,842
4	SJGS Replacement Resources 22-00270-UT	7,999,661	—	407.3	332,742	7,666,919
5	Renewable Energy	509,258	—	456	350,622	158,636
6	Pension & OPEB	173,678,991	—	926	10,798,699	162,880,292
7	Fuel Clause 22-00270-UT	30,486,195	—	501	28,447,432	2,038,763
8	Shutdown of San Juan Units 2&3 13-00390-UT	82,123,310	—	407.3	6,276,936	75,846,374
9	EIM Costs 18-00261-UT	15,189,151	—	407.3	3,758,140	11,431,011
10	Solar Direct 19-00058-UT	23,449	—	928	23,449	—
11	SJGS External Legal Expenses 22-00270-UT	475,866	—	407.3	19,793	456,073
12	COVID-19 Incremental Costs 20-00069-UT	3,328,280	—	407.3	1,233,987	2,094,293
13	Transportation Electrification 20-00237-UT	4,942,485	10,813,842	131	4,136,509	11,619,818
14	SJGS Obsolete Inventory 22-00270-UT	6,053,347	—	407.3	251,786	5,801,561
15	SJ County Ord-full Decomm 22-00270-UT	17,680,622	—	407.3	1,102,169	16,578,453
16	PVNGS Undepreciated Investment - 22-00270-UT	82,849,150	—	407.3	4,351,004	78,498,146
17	PVNGS SRP Over-Under 21-00083-UT	133,075	—	407.3	6,989	126,086
18	PVNGS Replacement resources 22-00270-UT	1,973,778	—	407.3	103,867	1,869,911
19	2024 Rate Change Expenses 22-00270-UT	3,905,358	—	407.3	966,274	2,939,084
20	SJGS Final ETA Decom 19-00018-UT	584,893	926,452	128/253	201,430	1,309,915
21	SJGS Final ETA Mine Rec 19-00018-UT	24,410,630	3,418,443	128/253	1,702,222	26,126,851
22	MTM Jurisdictional Hedging 19-00187-UT	5,737,494	—	244	5,737,494	—
23	TOD Rate Pilot Program 22-00270-UT	656,652	1,252,051		—	1,908,703
24	2025 Grid Mod Program 22-00058-UT	—	6,460,275		—	6,460,275
25	Community Solar Initial Startup Cost 23-00071-UT	1,244,025	721,442		—	1,965,467
26	Community Solar Ongoing Admin Costs 23-00071-UT	—	71,487	131	6,723	64,764
27	Community Solar Bill Credits 23-00071-UT	—	67,524	131	3,799	63,725
28	2025 Rate Change Expenses 24-00089-UT	—	2,017,349	407.3	201,735	1,815,614
29	Extended Day-Ahead Market Integration Costs 25-00059-	—	355,278		—	355,278
30						
31						
32						
33						
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42						
43						
44	TOTAL	550,470,990	29,281,393		74,059,721	505,692,662

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	Electric Distribution ROW Renewal	9,378,808	33,278	589	483,340	8,928,746
2	Electric Transmission ROW Renewal	62,000,505	6,524,035	567	4,225,666	64,298,874
3	New Generation	739,285	—	various	42,847	696,438
4	Afton CSA	5,384,409	1,489,921			6,874,330
5	Rate Case Expense	1,917,440		182.3	1,917,440	—
6	Western Spirit Contract Asset	32,017,643	9,687,866			41,705,509
7	Goodwill	51,632,295				51,632,295
8	Receivable under Insurance Policy	8,031,706	10,058,396			18,090,102
9	Other	—	675,878			675,878
10		—				—
11		—				—
12						
13						
14						
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41						
42						
43						
44						
45						
46						
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)	—	—	various		—
49	TOTAL	171,102,091				192,902,172

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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	See page 234.1	264,349,945	239,762,959
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	264,349,945	239,762,959
9	Gas		
10			
11			
12			
13			
14			
15	Other	—	—
16	TOTAL Gas (Enter Total of lines 10 thru 15	—	—
17	Other (Specify)	—	—
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	264,349,945	239,762,959

Notes

FOOTNOTE DATA

Page 234, Row 2, Column (a)

ACCUMULATED DEFERRED INCOME TAXES (ACCOUNT 190) (CONTINUED)
FOR THE YEAR ENDED DECEMBER 31, 2025

		BEGINNING BALANCE	ENDING BALANCE
	ELECTRIC		
1	PENSION COSTS	$ (36,677,515)	$ (37,819,525)
2	VACATION	1,044,790	1,017,478
3	CAPITALIZED INTEREST	25,615,596	31,410,926
4	GENERAL LIABILITY	72,027	72,027
5	ENVIRONMENTAL LIABILITY	(9,177)	(9,177)
6	REGULATORY LIABILITY	52,002,830	44,183,103
7	WORKERS' COMPENSATION LIABILITY	237,722	238,324
8	SELF INSURANCE	51,511	48,738
9	DECOMMISSIONING EXPENSE	156,862	161,372
10	SPENT FUEL DECOMMISSIONING	3,396,066	3,925,166
11	COAL MINE DECOMMISSIONING	23,168,285	19,284,558
12	COMPENSATION EXPENSE	4,083,529	2,980,760
13	PREPAID RENT REVENUE	9,156	7,438
14	RENEWABLE RIDER	1,215,617	330,126
15	ETC OVER/UNDER (SPE)	1,771,719	764,296
16	IBNR RESERVE	502,380	671,652
17	OTHER	251,967	328,701
18	SO2 ALLOWANCE CREDIT	876	—
19	ROW RESERVE	2,107,735	2,613,040
20	ENERGY EFFICIENCY	624,706	232,552
21	NET OPERATING LOSS CARRYFORWARDS	8,149,254	36,237,810
22	TAX CREDIT CARRYFORWARDS	96,390,998	97,915,084
23	NM ADVANCED ENERGY TAX CREDIT	541,428	494,799
24	WORKFORCE TRAINING RESERVE	25,401	—
25	LEASES	71,582,279	31,157,045
26	PREPAID ROW	223,603	181,012
27	ILLNESS	170,488	176,422
28	JOB TRAINING AND SEVERANCE	18,584	19,252
29	PATHNET	1,431,707	1,408,445
30	COVID-19 COST SAVINGS	119,021	—
31	SJGS RETIREMENT RATE CREDITS	39,819	19,860
32	SOLAR DIRECT	18,909	24,865
33	PVNGS LEASE COSTS	5,707,487	794,276
34	ENERGY TRANSITION COST	304,285	90,306
35	ENERGY STORAGE AGREEMENTS DEFERRAL	—	395,286
36	TRANSACTION COST	—	406,942
		$ 264,349,945	$ 239,762,959

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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		40,000,000	—	—
3				
4				
5	Total	40,000,000		
6	Preferred Stock (Account 204)			
7		10,000,000	100	102
8				
9				
10	Total	10,000,000		
11	Capital Stock (Accounts 201 and 204) - Data Conversion			
12				
13				
14				
15	Total	—		

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 BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
39,117,799	195,588,995	—	—	—	—	2
						3
						4
39,117,799	195,588,995					5
						6
115,293	11,529,299	—	—	—	—	7
						8
						9
115,293	11,529,299					10
						11
						12
						13
						14
—	—					15

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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	—
3	Increases (Decreases) from Sales of Donations Received from Stockholders	—
3.1		
4	Ending Balance Amount	—
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	970,372,591
15	Increases (Decreases) Due to Miscellaneous Paid-In Capital	
15.1	Equity Contributions from TXNM	123,300,000
16	Ending Balance Amount	1,093,672,591
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	—
21	TOTAL	1,093,672,591

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock Expense	19,748,140
2	Preferred Stock Expense	111,096
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	19,859,236

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)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)	Total Expense (e)	Total Premium (f)	Total Discount (g)
1	Bonds (Account 221)					
2	2.150% Farmington PCB	146,000,000	1,017,975	1,017,975		
3	3.875% Farmington PCB	37,000,000	294,536	294,536		
4	3.875% Farmington PCB	65,000,000	517,428	517,428		
5	3.875% Farmington PCB	60,000,000	477,626	477,626		
6	3.900% Farmington PCB	130,000,000	1,106,950	1,106,950		
7	3.875% Maricopa PCB	36,000,000	286,576	286,576		
8	0.875% Farmington PCB	40,045,000	287,850	287,850		
9	0.875% Maricopa PCB	39,300,000	282,494	282,494		
10	0.875% Maricopa PCB	21,000,000	150,951	150,951		
11						
12	2.59% SUN	80,000,000	459,480	459,480		
13	3.14% SUN	80,000,000	459,480	459,480		
14	3.85% SUN	250,000,000	2,998,046	2,303,046		695,000
15	3.45% SUN	104,000,000	732,012	732,012		
16	3.68% SUN	88,000,000	619,395	619,395		
17	3.93% SUN	38,000,000	267,466	267,466		
18	4.22% SUN	45,000,000	316,736	316,736		
19	4.50% SUN	20,000,000	140,772	140,772		
20	3.78% SUN	15,000,000	105,579	105,579		
21	4.60% SUN	85,000,000	598,279	598,279		
22	3.21% SUN	150,000,000	1,583,545	1,583,545		
23	3.57% SUN	50,000,000	527,848	527,848		
24	2.97% SUN	100,000,000	586,738	586,738		
25	2.29% SUN	50,000,000	293,369	293,369		
26	5.51% SUN	150,000,000	879,333	879,333		
27	5.92% SUN	50,000,000	293,111	293,111		
28	5.75% SUN	125,000,000	691,928	691,928		
29	6.13% SUN	175,000,000	968,699	968,699		
30	5.47% SUN	200,000,000	1,117,127	1,117,127		
31	6.03% SUN	150,000,000	837,845	837,845		
32	Subtotal	2,579,345,000	18,899,174	18,204,174	—	695,000

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. 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.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)	Line No.
						1
10/1/2021	4/1/2033	10/1/2021	4/1/2033	146,000,000	3,139,000	2
6/1/2024	6/1/2029	6/1/2024	6/1/2029	37,000,000	1,433,750	3
6/1/2024	6/1/2029	6/1/2024	6/1/2029	65,000,000	2,518,750	4
6/1/2024	6/1/2029	6/1/2024	6/1/2029	60,000,000	2,325,000	5
6/1/2023	6/1/2028	6/1/2023	6/1/2028	130,000,000	5,070,000	6
6/1/2024	6/1/2029	6/1/2024	6/1/2029	36,000,000	1,395,000	7
10/1/2021	10/1/2026	10/1/2021	10/1/2026	40,045,000	350,394	8
10/1/2021	10/1/2026	10/1/2021	10/1/2026	39,300,000	343,875	9
10/1/2021	10/1/2026	10/1/2021	10/1/2026	21,000,000	183,750	10
						11
7/14/2021	7/15/2033	7/14/2021	7/15/2033	80,000,000	2,072,000	12
7/14/2021	7/15/2041	7/14/2021	7/15/2041	80,000,000	2,512,000	13
8/11/2015	8/1/2025	8/11/2015	8/1/2025	—	5,614,583	14
5/15/2018	5/15/2025	5/15/2018	5/15/2025	—	1,335,533	15
5/15/2018	5/15/2028	5/15/2018	5/15/2028	88,000,000	3,238,400	16
5/15/2018	5/15/2033	5/15/2018	5/15/2033	38,000,000	1,493,400	17
5/15/2018	5/15/2038	5/15/2018	5/15/2038	45,000,000	1,899,000	18
5/15/2018	5/15/2048	5/15/2018	5/15/2048	20,000,000	900,000	19
8/1/2018	8/1/2028	8/1/2018	8/1/2028	15,000,000	567,000	20
8/1/2018	8/1/2048	8/1/2018	8/1/2048	85,000,000	3,910,000	21
4/30/2020	4/30/2030	4/30/2020	4/30/2030	150,000,000	4,815,000	22
4/30/2020	4/29/2039	4/30/2020	4/29/2039	50,000,000	1,785,000	23
12/2/2021	12/30/2041	12/2/2021	12/30/2041	100,000,000	2,970,000	24
12/2/2021	12/30/2031	12/2/2021	12/30/2031	50,000,000	1,145,000	25
4/28/2023	4/28/2035	4/28/2023	4/28/2035	150,000,000	8,265,000	26
4/28/2023	4/28/2053	4/28/2023	4/28/2053	50,000,000	2,960,000	27
4/20/2025	6/1/2032	4/20/2025	6/1/2032	125,000,000	4,951,389	28
4/20/2025	6/1/2037	4/20/2025	6/1/2037	175,000,000	7,390,056	29
7/31/2025	7/31/2031	7/31/2025	7/31/2031	200,000,000	4,588,722	30
7/31/2025	7/31/2036	7/31/2025	7/31/2036	150,000,000	3,793,875	31
				2,225,345,000	82,965,477	32

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)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)	Total Expense (e)	Total Premium (f)	Total Discount (g)
33	Reacquired Bonds (Account 222)					
34						
35						
36						
37	Subtotal	—	—	—	—	—
38	Advances from Associated Companies (Account 223)					
39						
40						
41						
42	Subtotal	—	—	—	—	—
43	Other Long Term Debt (Account 224)					
44	$200M Term Loan	200,000,000	—	—		
45	$195M Term Loan	195,000,000	—	—		
46	$120M Term Loan	120,000,000	—	—		
47						
48	Subtotal	515,000,000	—	—	—	—
49	TOTAL	3,094,345,000	18,899,174	18,204,174	—	695,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. 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.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (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.
						33
						34
						35
						36
				—	—	37
						38
						39
						40
						41
				—	—	42
						43
5/10/2024	11/10/2025	5/10/2024	11/10/2025	—	9,204,708	44
1/21/2025	7/21/2026	1/21/2025	7/21/2026	195,000,000	9,775,447	45
11/10/2025	5/10/2027			120,000,000	829,826	46
						47
				315,000,000	19,809,981	48
				2,540,345,000	102,775,458	49

FOOTNOTE DATA

Page 257.1, Row 45, Column (m)

	December 31, 2025
Account 427	$ 101,771,649
Capitalized Interest	1,003,809
Total Interest	$ 102,775,458

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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)	87,629,134
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		28,959,955
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		172,830,171
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		74,287,762
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		323,921,033
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	(108,789,535)
28	Show Computation of Tax:	
29		
30	Regular Tax @ 21%	(22,845,802)
31		
32	Accrual to Return Adjustment to Current Income Tax Expense	(3,572,340)
33	Other Adjustments	(378,063)
34	NOL Deferral	17,752,127
35		—
36		—
37		
38	Federal Tax Payable	(9,044,078)
39		
40		
41		
42		
43		
44		

FOOTNOTE DATA

Page 261, Row 5, Column (b)

Taxable Income not Recorded for Book Purposes:		
Contributions in Aid of Construction	$	24,396,274
EIM Costs		3,758,140
SJGS Decommissioning Trust		447,930
Renewable Energy		350,622
PVNGS SRP Over-Under		6,989
Total	$	28,959,955

Page 261, Row 10, Column (b)

Deductions Recorded on Books not Deducted for Return:		
Pension	$	62,525,923
Fuel Clause		28,447,432
Capitalized Interest		16,374,935
State Income Tax		10,775,823
Section 174 Deduction		8,845,915
SJ Energy Transition Property		6,945,241
SJGS Stranded Costs		6,276,936
Asset Retirement Obligations		6,185,626
Non-Deductible Compensation		6,079,923
PVNGS Unit 1 Undepreciated Investment		4,036,072
PVNGS Dry Casks		2,083,045
General Expenses Rights-of-Way		1,989,368
Rate Rider 12 UG Rate		1,978,909
Rate Case Expenses		1,917,376
Transaction Costs		1,602,115
ESA Deferral		1,556,225
Hedge Loss Amortization		844,446
Covid-19 Costs		765,410
Self Insurance		751,915
Loss on Reacquired Debt		391,099
Lease Expense		369,495
SJGS Replacement Resources		332,742
PVNGS Unit 2 Undepreciated Investment		314,931
Non-Deductible Parking		309,000
Demolition Costs		285,804
Non-Deductible Meals		277,240
SJGS Obsolete Inventory		251,786
Vacation		127,211
PVNGS Replacement Resources		103,867
Solar Direct		23,448
Illness		23,363
SJGS External Legal Fees		19,793
Environmental Expenses		17,757
Total	$	172,830,171

FOOTNOTE DATA

Page 261, Row 15, Column (b)

Income per Books not Included in the Return:		
AFUDC	$	23,646,919
PVNGS Decommissioning Trust		18,668,173
WS - Transmission Revenue		9,687,866
Federal Income Tax		8,372,646
ETC Over/Under (SPE)		3,966,186
Renewable Rider		3,486,143
TOD Rate Pilot Program		1,252,051
Municipal Interest		1,164,520
Dividends Received Deduction		1,145,168
SJGS Reclamation Trust		996,148
Renewables Federal Grant Amortization		962,888
EDAM		355,279
New Mexico Advanced Energy Tax Credit		183,576
Prepaid Revenue		163,261
Navajo Workforce Training		100,000
SJGS Retirement Rate Credits		78,576
PVNGS Gain Amortization		39,828
Four Corners Trust		18,534
Total	$	74,287,762

Page 261, Row 20, Column (b)

Deductions on Return not Charged Against Book Income:		
Repairs Expense	$	148,661,650
Sec 263A Adjustment		59,833,143
Gain / Loss on Asset Disposition		34,676,799
PVNGS Lease Costs		19,343,121
Depreciation		15,449,472
Coal Mine Decommissioning		15,290,085
Transportation Electrification		6,677,332
Grid Modernization		5,661,967
Post Employment Benefits		4,202,463
Incentive Compensation		4,091,572
Prepaid Expenses		1,797,368
SJGS Final ETA Mine Reclamation		1,716,222
Energy Efficiency Programs		1,543,897
PVNGS Decommissioning - Qualified		1,300,000
Community Solar		849,931
Rate Change Expenses		849,340
Energy Transition Cost		842,428
SJGS Final ETA Decommissioning		725,021
Fines and Penalties		121,570
Workers Compensation		94,044
Pathnet		91,581
PVNGS Licensing Amortization		53,136
Extended Leave		45,444
SO2 Allowance Credit		3,447
Total	$	323,921,033

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR: Taxes Accrued (Account 236) (e)	BALANCE AT BEGINNING OF YEAR: Prepaid Taxes (Include in Account 165) (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjust-ments (i)
1.1	Federal	Federal Tax		2025	(6,722,736)		(9,044,078)	(10,773,657)	
1.2	Federal Withholding Tax	Federal Tax		2025					
2	Total Federal Tax				(6,722,736)	—	(9,044,078)	(10,773,657)	—
3.1	Worker's Compensation	State Tax	NM	2024	2,024	—		2,024	—
3.2	Worker's Compensation	State Tax	NM	2025	—	—	8,653	6,373	—
3.3	Weight Distance	State Tax	NM	2024	1,245	—	180	1,425	—
3.4	Weight Distance	State Tax	NM	2025	—	—	5,862	4,506	—
3.5	State	State Tax	NM	2025	(9,586,625)	—	(1,113,967)	(2,562,079)	—
4	Total State Tax				(9,583,356)	—	(1,099,272)	(2,547,751)	—
5.1									
5.2									
6	Total Local Tax				—	—	—	—	—
7.1									
7.2									
8	Total Other Tax				—	—	—	—	—
9.1		Property Tax	NM	2023	—	—	55	55	—
9.2		Property Tax	NM	2024	15,096,638	—	52	15,096,690	—
9.3		Property Tax	NM	2025			36,318,208	18,258,698	
9.4		Property Tax	AZ	2023	—	—			—
9.5		Property Tax	AZ	2024	2,290,197	—		2,290,197	—
9.6		Property Tax	AZ	2025	—		3,546,578	1,817,781	
10	Total Property Tax				17,386,835	—	39,864,893	37,463,421	—
11.1									
12	Total Real Estate Tax				—	—	—	—	—
13.1	Federal	Unemployment		2024	1,605	—		1,605	—
13.2	Federal	Unemployment		2025	—	—	41,293	39,811	—
13.3	State	Unemployment	NM	2024	32,278	—		32,278	—
13.4	State	Unemployment	AZ	2025	—	—	346	346	—
13.5	State	Unemployment	NM	2025	—		527,199	508,944	—
14	Total Unemployment Tax				33,883	—	568,838	582,984	—
15.1	Gross Receipts Tax	Sales And Use	NM	2023	—	—	—		—
15.3	Gross Receipts Tax	Sales And Use	NM	2025	740,625	—		740,625	—
15.4	Transaction Privilege Tax	Sales And Use	AZ	2025		—			—
16	Total Sales and Use Tax				740,625	—	—	740,625	—
17.1									
17.2									
18	Total Income Tax				—	—	—	—	—
19.1	Federal	Excise Tax		2024	—	32,349	32,349		—
19.2	Federal	Excise Tax		2025			10,518	42,073	
20	Total Excise Tax				—	32,349	42,867	42,073	—
21.1									

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. 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 (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				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)	
(4,993,157)		(9,044,078)			—	1.1
						1.2
(4,993,157)	—	(9,044,078)	—	—	—	2
—	—		—	—	—	3.1
2,280	—	8,653	—	—	—	3.2
—	—	180	—	—	—	3.3
1,356	—	5,862	—	—	—	3.4
(8,138,513)	—	(1,113,967)		—	—	3.5
(8,134,877)	—	(1,099,272)	—	—	—	4
						5.1
						5.2
—	—	—	—	—	—	6
						7.1
						7.2
—	—	—	—	—	—	8
—	—	55			—	9.1
—	—	85			(33)	9.2
18,059,510	—	36,318,208				9.3
—	—	(15,156)			15,156	9.4
—	—	(90)			90	9.5
1,728,797	—	3,438,338			108,240	9.6
19,788,307	—	39,741,440	—	—	123,453	10
						11.1
—	—	—	—	—	—	12
—	—		—	—		13.1
1,482	—	22,626	—	—	18,667	13.2
—	—	—	—	—		13.3
—	—	346	—	—		13.4
18,255		288,721			238,478	13.5
19,737	—	311,693	—	—	257,145	14
—	—	(10,649)	—	—	10,649	15.1
—	—	392	—	—	(392)	15.3
—	—	—	—	—	—	15.4
—	—	(10,277)	—	—	10,277	16
						17.1
						17.2
—	—	—	—	—	—	18
—		32,349	—	—	—	19.1
—	31,555	10,518				19.2
—	31,555	42,867	—	—	—	20
						21.1

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
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3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5)	Type of Tax	State	Tax Year	BALANCE AT		Taxes Charged During Year	Taxes Paid During Year	Adjust-ments
					Taxes Accrued (Account 236)	Prepaid Taxes (Include in Account 165)			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
21.2									
22	Total Fuel Tax				—	—	—	—	—
23.1									
23.2									
24	Total Federal Insurance Tax				—	—	—	—	—
25.1	Franchise Tax	Franchise Tax	CA	2025					
26	Total Franchise Tax				—	—	—	—	—
27		Miscellaneous Other Tax				—		—	—
28	Total Miscellaneous Other Tax				—	—	—	—	—
29.1									
29.2									
30	Total Other Federal Tax				—	—	—	—	—
31.1									
31.2									
32	Total Other State Tax				—	—	—	—	—
33.1	Native American	Other Property Tax	NM	2024	1,097,058			1,097,058	—
33.2	Native American	Other Property Tax	NM	2025			3,290,408	2,275,115	—
33.3	Native American - Prepaid	Other Property Tax	NM	2025	—	274,141	274,141		—
34	Total Other Property Tax				1,097,058	274,141	3,564,549	3,372,173	—
35.1	Compensating	Other Use Tax	NM	2021	—	—			—
35.2									
36	Total Other Use Tax				—	—	—	—	—
37.1									
37.2									
38	Total Other Advalorem Tax				—	—	—	—	—
39.1									
39.2									
40	Total Other License and Fees				—	—	—	—	—
41.1	FICA	Payroll Tax		2023	—	—			—
41.2	FICA	Payroll Tax		2024	—	—			—
41.3	FICA	Payroll Tax		2025		—	7,360,057	7,360,057	—
42	Total Payroll Tax				—	—	7,360,057	7,360,057	—
43.1									
43.2									
44	Total Advalorem Tax				—	—	—	—	—
45.1	Miscellaneous Payroll	Other Allocated Tax	NM	2024	—	—	—	—	—
45.2	Miscellaneous Payroll Tax	Other Allocated Tax	NM	2025	—	—	—	—	—

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. 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 (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				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)	
						21.2
—	—	—	—	—	—	22
						23.1
						23.2
—	—	—	—	—	—	24
		800			(800)	25.1
—	—	800	—	—	(800)	26
—	—	—	—	—		27
—	—	—	—	—	—	28
						29.1
						29.2
—	—	—	—	—	—	30
						31.1
						31.2
—	—	—	—	—	—	32
—	—		—	—		33.1
1,015,293	—	3,472,673	—	—	(182,265)	33.2
—	—	274,141	—	—		33.3
1,015,293	—	3,746,814	—	—	(182,265)	34
—	—	(18)	—	—	18	35.1
						35.2
—	—	(18)	—	—	18	36
						37.1
						37.2
—	—	—	—	—	—	38
						39.1
						39.2
—	—	—	—	—	—	40
—	—	(942)	—	—	942	41.1
—		(225,850)			225,850	41.2
—	—	4,187,211	—	—	3,172,846	41.3
—	—	3,960,419	—	—	3,399,638	42
						43.1
						43.2
—	—	—	—	—	—	44
—	—	617	—	—	(617)	45.1
—	—	1,950,077	—	—	(1,950,077)	45.2

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
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4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT Taxes Accrued (Account 236) (e) December	BALANCE AT Prepaid Taxes (Include in Account 165) (f) December	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjust-ments (i)
45.3	Miscellaneous Other	Other Allocated Tax	NM	2023	—	—	—	—	—
45.4	Miscellaneous Other	Other Allocated Tax	NM	2024					
45.5	Miscellaneous Other	Other Allocated Tax	NM	2025	—	—	—	—	—
46	Total Other Allocated Tax				—	—	—	—	—
47.1									
47.2									
48	Total Severance Tax				—	—	—	—	—
49.1									
49.2									
50	Total Penalty Tax				—	—	—	—	—
51.1	Franchise Fees	Other Taxes and Fees	NM	2024	—		—	—	—
51.2	Franchise Fees	Other Taxes and Fees	NM	2025	—	—	—	—	—
51.3	Regulatory Comm Fee (S&I)	Other Taxes and Fees	NM	2025	216,813		6,285,506	6,163,601	—
51.4	Miscellaneous Fees	Other Taxes and Fees	NM	2025	—		—	—	
52	Total Other Taxes and Fees				216,813	—	6,285,506	6,163,601	—
53	TOTAL				3,169,122	306,490	47,543,360	42,403,526	—

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. 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 (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				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)	
—		(77)			77	45.3
		627			(627)	45.4
—		(3,428)			3,428	45.5
—	—	1,947,816	—	—	(1,947,816)	46
						47.1
						47.2
—	—	—	—	—	—	48
						49.1
						49.2
—	—	—	—	—	—	50
—		2			(2)	51.1
—	—	(118)			118	51.2
338,718		5,946,790			338,718	51.3
—		85			(85)	51.4
338,718	—	5,946,759	—	—	338,749	52
8,034,021	31,555	45,544,963	—	—	1,998,399	53

Page 263.2, Row 53, Column (o)

		December 31, 2025
Property Taxes posted to other balance sheet accounts:		$ (33)
Arizona Property Tax on leased assets charged to acct 525:		123,486
Payroll Taxes capitalized to various accounts:		3,524,468
FICA	3,267,323	
Federal Unemployment Tax	18,667	
State Unemployment Tax	238,478	
Gross Receipts Tax posted to other balance sheet accounts:		10,277
Native American Tax amortization included in prepaid ROW 186:		(182,265)
Misc Other Payroll Taxes billed by Operating Agent:		(1,980,308)
Misc Other Payroll Taxes billed to Participants:		32,492
Social Security Tax posting to other balance sheet accounts		132,315
Regulatory Comm Fee (S&I) collected from customers:		338,718
Other Misc Taxes posting to other balance sheet accounts:		(751)
TOTAL		$ 1,998,399

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	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	Balance at Beginning of Year	Deferred for Year		Allocations to Current Year's Income		Adjustments
			Account No	Amount	Account No.	Amount	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Electric Utility						
2	3%	—		—		—	—
3	4%	—		—		—	—
4	7%	901,281		—	411.4	23,314	—
5	10%	3,804,944		—	411.4	146,123	—
6	0.3	76,361,848		—	411.4	—	—
7		—		—		—	—
8	TOTAL	81,068,074		—		169,437	—
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
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39							
40							
41							
42							
43							
44							
45							
46							
47	OTHER TOTAL	—					
48	GRAND TOTAL	—					

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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
—			3
877,967			4
3,658,821			5
76,361,848			6
—			7
80,898,636			8
			9
			10
			11
			12
			13
			14
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			39
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			41
			42
			43
			44
			45
			46
—			47
—			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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 (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Legal Liabilities	420,000	Various	328,000	—	92,000
2	Environmental	617,559	Various	603,679	621,436	635,316
3	Distribution ROW Reserves	338,209	589	—	44,503	382,712
4	Transmission ROW Reserves	7,959,862	567	453,343	2,398,208	9,904,727
5	Coal Mine Decommissioning	91,212,641	131	21,474,322	6,184,238	75,922,557
6	Dry Cask-Spent Nuclear Fuel	13,370,179	131	1,518,724	3,601,769	15,453,224
7	Transmission Studies	7,927,203	Various	30,441,222	28,651,671	6,137,652
8	FIN 48 Tax Liability	11,920,088	Various	976	602,210	12,521,322
9	Customer Deposits	8,570,496	131	111,609	833,387	9,292,274
10	Transmission ROW TEP	880,319	567	167,680	—	712,639
11	Other	747,295	Various	39,826	—	707,469
12						
13						
14						
15						
16						
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42						
43						
44						
47	TOTAL	143,963,851		55,139,381	42,937,422	131,761,892

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
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)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities	—	—	—
4	Pollution Control Facilities	273,697	172	3,900
5	Other (provide details in footnote):	1,696,989	—	—
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	1,970,686	172	3,900
9	Gas			
10	Defense Facilities	—		
11	Pollution Control Facilities	—		
12	Other (provide details in footnote):	—		
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)	—	—	—
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	1,970,686	172	3,900
18	Classification of TOTAL			
19	Federal Income Tax	1,558,929	172	3,082
20	State Income Tax	411,757	—	818
21	Local Income Tax	—		

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
		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
—	—	—	—	—	—	—	3
—	—	—	—	—	—	269,969	4
—	—	—	—	—	—	1,696,989	5
						—	6
						—	7
—	—		—		—	1,966,958	8
							9
					—	—	10
						—	11
						—	12
						—	13
						—	14
—	—		—		—	—	15
						—	16
—	—		—		—	1,966,958	17
							18
—	—	—	—	—	—	1,556,019	19
—	—	—	—	—	—	410,939	20
						—	21

NOTES (Continued)

FOOTNOTE DATA

Page 272, Row 4, Column (b)

Four Corners Pollution Control Facilities fully amortized in accordance with IRC Sect 169.

Page 272, Row 5, Column (b)

Regulatory Asset Deferred

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

ACCUMULATED DEFFERED 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 (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	573,991,039	117,944,312	43,790,550
3	Gas	—	—	—
4	Other (Specify)	—	—	—
5	TOTAL (Enter Total of lines 2 thru 4)	573,991,039	117,944,312	43,790,550
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	573,991,039	117,944,312	43,790,550
10	Classification of TOTAL			
11	Federal Income Tax	414,900,389	93,575,051	35,693,926
12	State Income Tax	159,090,650	24,369,261	8,096,624
13	Local Income Tax	—		

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
194,219	8,550	182.3/254/190	1,057,508	182.3/190/281	3,369,221	650,642,183	2
—	—	—	—	—	—	—	3
—	—	—	—	—	—	—	4
194,219	8,550		1,057,508		3,369,221	650,642,183	5
							6
							7
							8
194,219	8,550		1,057,508		3,369,221	650,642,183	9
							10
153,504	8,550	—	825,606	—	2,630,380	474,731,242	11
40,715	—	—	231,902	—	738,841	175,910,941	12
						—	13

NOTES (Continued)

FOOTNOTE DATA

Page 274, Row 2, Column (b)

Accounting for liberalized depreciation was approved by the Commission effective December 31, 1965 under General Order 18, Case No. 799. ADR and ACRS depreciation methods were approved by the Commission in a letter dated December 30, 1973 and under Case 1693, respectively. Case 1693, accounting for ACRS depreciation was the first order effective after the enactment of ERTA in 1982 and was effective prior to January 1983.

For FERC jurisdiction only, additional taxes are provided to account for the timing difference created as a result of the difference between book lives and guideline class lives. The amount deferred is based on the percentage of demand required by FERC customers.

Deferred taxes are provided as a result of the timing difference created by certain start up costs related to the Palo Verde Nuclear Generating Station, amortized under IRC Section 195.

Page 275, Row 2, Column (j)

Net Regulatory Asset and Liability Activity.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

ACCUMULATED DEFFERED 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)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Fuel Costs	7,743,586	6,147,602	13,373,335
4	Computer Software	—	—	—
5	Loss on Reacquired Debt	1,141,018	4,575	103,915
6	Regulatory Asset Deferrals	68,797,240	—	—
7	Other (see pages 276a and 277b)	274,860,328	37,302,274	74,050,165
8				
9	TOTAL Electric (Total of lines 3 thru 8)	352,542,172	43,454,451	87,527,415
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	—	—	—
18	TOTAL Other	—	—	—
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	352,542,172	43,454,451	87,527,415
20	Classification of TOTAL			
21	Federal Income Tax	292,964,114	35,136,536	69,544,794
22	State Income Tax	59,598,191	8,317,915	17,982,621

NOTES

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
—	—	—	—	—	—	517,853	3
—	—	—	—	—	—	—	4
—	—	—	—	—	—	1,041,678	5
—	—	182.3	292,860	182.3	839,493	69,343,873	6
12,943,028	14,697,556	190	1,044	219	1,987	236,358,852	7
							8
12,943,028	14,697,556		293,904		841,480	307,262,256	9
							10
							11
							12
							13
							14
							15
							16
—	—		—		—	—	17
—	—		—		—	—	18
12,943,028	14,697,556		293,904		841,480	307,262,256	19
							20
10,360,353	11,730,134		229,454		656,950	257,613,571	21
2,582,675	2,967,422		64,450		184,530	49,668,818	22

NOTES (Continued)

FOOTNOTE DATA

Page 277, Row 7, Column (k)

Accumulated Incomes Taxes -- other (account 283)
(Continued)

Line No.	Account Subdivisions	Balance at Beginning of Year	CHANGES DURING YEAR: Amounts Debited To Account 410.1	CHANGES DURING YEAR: Amounts Credited To Account 411.1	CHANGES DURING YEAR: Amounts Debited To Account 410.2	CHANGES DURING YEAR: Amounts Credited To Account 411.2	ADJUSTMENTS: Debits Acct No.	ADJUSTMENTS: Debits Amount	ADJUSTMENTS: Credits Acct No.	ADJUSTMENTS: Credits Amount	Balance at End of Year
7a	Nuclear Decommissioning - Qualified	$ 22,734,903	$ 345,410	$ 15,206	$ —	$ —		$ —		$ —	$ 23,065,107
7b	Nuclear Decommissioning - Non Qualified	63,100,574	—	—	11,791,716	1,646,984		—	219	1,987	73,247,293
7c	Hedge Loss	2,035,744	—	—	9,878	224,370		—		—	1,821,252
7d	Renewable Energy Expenses	129,353	4,103	93,161	—	—		—		—	40,295
7e	Book Capitalized Interest	6,007,725	266,713	11,742	—	—		—		—	6,262,696
7f	Prepaid Expenses	2,687,237	6,456,661	6,000,045	—	—		—		—	3,143,853
7g	Rate Case Expense	580,164	22,428	509,447	—	—		—		—	93,145
7h	EIM Costs	3,858,089	43,959	998,538	—	—		—		—	2,903,510
7i	Benefits - Retiree Medical	9,161,790	1,116,594	49,155	—	—		—		—	10,229,229
7j	PVNGS Decommissioning Interest	(37,413,986)	—	—	1,141,434	12,826,199		—		—	(49,098,751)
7k	Four Corners Trust	—	4,924	217	—	—	190	1,044		—	3,663
7l	Energy Efficiency	—	2,452,042	2,452,042	—	—		—		—	—
7m	Lease Asset	72,386,873	16,925,336	57,444,424	—	—		—		—	31,867,785
7n	COVID-19 Costs	607,265	22,429	509,472	—	—		—		—	120,222
7o	SJGS Replacement Resources	2,031,937	3,893	88,410	—	—		—		—	1,947,420
7p	Grid Modernization	—	1,504,385	66,228	—	—		—		—	1,438,157
7q	SJGS External Legal Fees	120,871	233	5,260	—	—		—		—	115,844
7r	Transportation Electrification	1,255,406	1,857,089	161,026	—	—		—		—	2,951,469
7s	SJGS Obsolete Inventory	1,537,568	2,945	66,899	—	—		—		—	1,473,614
7t	WS Transmission Revenue	8,132,577	2,574,067	113,319	—	—		—		—	10,593,325
7u	2024 Rate Change	991,973	11,303	256,740	—	—		—		—	746,536
7v	PVNGS Replacement Resources	501,345	1,215	27,597	—	—		—		—	474,963
7w	PVNGS SRP Over-Under	33,801	82	1,857	—	—		—		—	32,026
7x	PVNGS Unit 1 Undepreciated Investment	10,441,362	25,251	573,594	—	—		—		—	9,893,019
7y	PVNGS Unit 1 Undepreciated Investment Post Amortization	9,079,665	21,959	498,790	—	—		—		—	8,602,834
7z	UG Rate Rider	900,631	23,148	525,796	—	—		—		—	397,983
7aa	Renewable Rider	—	740,685	740,685	—	—		—		—	—
7ab	SJGS Energy Transition Property (SPE)	85,365,066	81,239	1,845,351	—	—		—		—	83,600,954
7ac	COVID Bad Debt	238,128	446,322	272,716	—	—		—		—	411,734
7ad	Community Solar	315,986	225,827	9,942	—	—		—		—	531,871
7ae	PVNGS Unit 2 Undepreciated Investment	708,023	1,713	38,905	—	—		—		—	670,831
7af	PVNGS Unit 2 Undepreciated Investment Post Amortization	814,883	1,971	44,773	—	—		—		—	772,081
7ag	SJGS Final ETA Decommissioning	148,565	192,638	8,481	—	—		—		—	332,722
7ah	SJGS Final ETA Mine Reclamation	6,200,373	456,001	20,075	—	—		—		—	6,636,299
7ai	TOD Rate Pilot Program	166,792	332,669	14,645	—	—		—		—	484,816
7aj	2025 Rate Change	—	529,042	67,871	—	—		—		—	461,171
7ak	Energy Storage Agreements Deferral	—	513,599	513,599	—	—		—		—	—
7al	Extended Day - Ahead Market	—	94,398	4,156	—	—		—		—	90,242
7am	Other	(355)	—	—	—	3		—		—	(358)
	TOTAL Electric	$274,860,328	$37,302,273	$74,050,164	$12,943,028	$14,697,556		$ 1,044		$ 1,987	$236,358,852

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	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	Income Tax	253,158,266	190/411	31,689,626	—	221,468,640
2	SO2 Allowance Credit, March 2011	3,448	407.4	3,448	—	—
3	Renewable Energy Grant	11,185,181	407.4	962,887	—	10,222,294
4	Renewable rider	4,785,837	456.0	3,486,143	—	1,299,694
5	NM Energy Credit	2,131,584	407.4	183,576	—	1,948,008
6	Energy Efficiency Program Costs	2,459,439	928	1,543,897	—	915,542
7	PVNGS Rate Refunds 22-00270-UT	22,470,156	131	19,343,121	—	3,127,035
8	COVID-19 Cost Savings 20-00069-UT	468,578	407.4	468,578	—	—
9	SJGS Rate Refunds 19-00018-UT	156,768	131	78,576	—	78,192
10	Energy Transition Cost	1,197,960	407	842,428	—	355,532
11	Energy Storage Agreements 24-00089-UT	—	501	—	1,556,225	1,556,225
12						
13						
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36						
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38						
39						
40						
41	TOTAL	298,017,217		58,602,280	1,556,225	240,971,162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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	541,563,603	528,978,323
3	(442) Commercial and Industrial Sales		—
4	Small (or Comm.) (See Instr. 4)	455,538,941	451,084,612
5	Large (or Ind.) (See Instr. 4)	171,249,659	146,685,577
6	(444) Public Street and Highway Lighting	6,448,386	6,024,943
7	(445) Other Sales to Public Authorities	17,308,594	16,717,412
8	(446) Sales to Railroads and Railways	—	—
9	(448) Interdepartmental Sales	—	—
10	TOTAL Sales to Ultimate Consumers	1,192,109,183	1,149,490,867
11	(447) Sales for Resale	97,754,662	66,494,406
12	TOTAL Sales of Electricity	1,289,863,845	1,215,985,273
13	(Less) (449.1) Provision for Rate Refunds	—	—
14	TOTAL Revenues Net of Prov. for Refunds	1,289,863,845	1,215,985,273
15	Other Operating Revenues		
16	(450) Forfeited Discounts	1,225,145	1,099,912
17	(451) Miscellaneous Service Revenues	1,427,471	1,037,612
18	(453) Sales of Water and Water Power	—	—
19	(454) Rent from Electric Property	3,683,153	3,637,065
20	(455) Interdepartmental Rents	—	—
21	(456) Other Electric Revenues	11,412,453	(8,527,887)
22	(456.1) Revenues from Transmission of Electricity of Others	149,669,466	141,058,028
23	(457.1) Regional Control Service Revenues	—	—
24	(457.2) Miscellaneous Revenues	—	—
25			
26	TOTAL Other Operating Revenues	167,417,688	138,304,730
27	TOTAL Electric Operating Revenues	1,457,281,533	1,354,290,003

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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
3,311,808	3,397,273	496,914	492,945	2
			—	3
3,627,611	3,654,150	58,496	58,503	4
2,886,927	2,607,603	180	183	5
33,499	33,795	748	753	6
185,608	181,834	247	254	7
—	—		—	8
—	—		—	9
10,045,453	9,874,655	556,585	552,638	10
4,057,809	3,275,260	36	27	11
14,103,262	13,149,915	556,621	552,665	12
—	—		—	13
14,103,262	13,149,915	556,621	552,665	14

Line 12, column (b) includes $(4,458,561) of unbilled revenues

Line 12, column (d) includes (23,691) MWH relating to unbilled revenues

FOOTNOTE DATA

Page 300, Row 17, Column (b)

	December 31, 2025	December 31, 2024
Connection Charges:	$ 640,788	$ 502,567
Return Payment Charges and Associated Fees	647,594	378,798
Other	139,089	156,247
Total	$ 1,427,471	$ 1,037,612

Page 300, Row 21, Column (b)

	December 31, 2025	December 31, 2024
Renewable Energy, Including Excess Return	$ 3,244,209	$ (9,627,385)
Energy Efficiency	(241,029)	(92,591)
OATI West Connect	1,635,138	1,027,470
TOD Rate Pilot lost revenue	1,252,051	
Gas Transportation Sale for Resale	5,522,084	
Other	—	164,619
Total	$ 11,412,453	$ (8,527,887)

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of 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 each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
	Residential Sales					
1	1A Residential Service	3,313,674	395,711,034	496,064	6,680	0.1194
2	1B Residential Service--TOU	9,074	957,818	850	10,675	0.1056
3	6 Private Area Lighting Svc	1,697	332,989	—		0.1962
4	Fuel Adjustment Clause		99,160,941	—		
5	Energy Efficiency		21,852,485	—		
6	Renewable Rate Rider		22,554,921	—		
7	Transportation Electrification Program		3,352,110	—		
8	Residential Sales Billed	3,324,445	543,922,298	496,914	6,690	0.1636
9	Residential Sales Unbilled	(12,637)	(2,358,695)	—		
10	Residential Sales Total	3,311,808	541,563,603	496,914	6,665	0.1635
	Commercial Sales					
11	10A Irrigation Service	3,242	275,500	107	30,299	0.0850
12	10B Irrigation Service--TOU	20,455	1,685,897	207	98,816	0.0824
13	15B Large Svc for Public Univ	83,202	4,267,057	1	83,202,000	0.0513
14	2A Small Power Service	921,762	101,629,802	53,346	17,279	0.1103
15	2B Small Power Service--TOU	11,332	1,255,455	433	26,171	0.1108
16	35B Large Power Service--TOU	27,202	1,085,783	1	27,201,600	0.0399
17	3B General Power Service--TOU	1,445,100	114,054,689	2,991	483,149	0.0789
18	3C General Power Service--TOU	284,388	28,077,775	1,028	276,642	0.0987
19	3D Pilot Municipalities & Counties General Power--TOU	94,332	7,208,996	152	620,605	0.0764
20	3E Pilot Municipalities & Counties General Power--TOU	23,340	2,521,599	80	291,750	0.1080
21	3F Non-Residential Charging Station-Pilot	6,515	572,872	12	542,893	0.0879
22	4B Large Power Svc--TOU	705,976	45,169,068	135	5,229,452	0.0640
23	6 Private Area Lighting Svc	10,025	1,795,272	—		0.1791
24	11B Water & Sewage Pump--TOU	1,794	108,554	3	717,479	0.0605
25	Fuel Adjustment Clause		103,610,733	—		
26	Energy Efficiency		17,882,847	—		
27	Renewable Rate Rider		25,745,567	—		
28	Transportation Electrification Program		691,341	—		
29	Commercial Sales Billed	3,638,665	457,638,807	58,496	62,204	0.1258
30	Commercial Sales Unbilled	(11,054)	(2,099,866)	—		
31	Commercial Sales Total	3,627,611	455,538,941	58,496	62,015	0.1256
	Industrial Sales					
32	2A Small Power Service	3,023	323,155	126	23,992	0.1069
33	2B Small Power Service--TOU	8	1,181	2		
34	30B-Lg Svc (Manuf>30MW)	644,378	25,405,475	1	644,378,000	0.0394
35	33B General Power Service--TOU	3,124	196,969	1	3,124,000	0.0631
36	35B Large Power Service--TOU	136,426	4,821,584	3	45,475,333	0.0353
37	36B Special Service Rate	1,502,260	53,952,322	1	1,502,260,000	0.0359

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of 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 each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
38	3B General Power Service--TOU	14,200	1,014,279	17	835,294	0.0714
39	3C General Power Service--TOU	1,498	177,217	6	249,667	0.1183
40	4B Large Power Svc--TOU	156,804	9,551,000	21	7,466,857	0.0609
41	5B Industrial Power Svc--TOU	14,453	1,395,056	1	14,453,000	0.0965
42	6 Private Area Lighting Svc	69	11,804	—		0.1711
43	9/11 - Industrials Power Service	410,684	27,704,479	1	410,684,000	0.0675
44	Fuel Adjustment Clause		38,917,246	—		
45	Energy Efficiency		1,176,845	—		
46	Renewable Rate Rider		66,807	—		
47	Transportation Electrification Program		6,534,240	—		
48	Industrial Sales Billed	2,886,927	171,249,659	180	16,038,483	0.0593
49	Industrial Sales Unbilled					
50	Industrial Sales Total	2,886,927	171,249,659	180	16,038,483	0.0593
	Commercial and Industrial Sales					
51	10A Irrigation Service	3,242	275,500	107	30,299	0.0850
52	10B Irrigation Service--TOU	20,455	1,685,897	207	98,816	0.0824
53	15B Large Svc for Public Univ	83,202	4,267,057	1	83,202,000	0.0513
54	2A Small Power Service	924,785	101,952,957	53,472	17,295	0.1102
55	2B Small Power Service--TOU	11,340	1,256,636	435	26,069	0.1108
56	30B-Lg Svc (Manuf>30MW)	644,378	25,405,475	1	644,378,000	0.0394
57	33B General Power Service--TOU	3,124	196,969	1	3,124,000	0.0631
58	35B Large Power Service--TOU	163,628	5,907,367	4	40,907,000	0.0361
59	36B Special Service Rate	1,502,260	53,952,322	1	1,502,260,000	0.0359
60	3B General Power Service--TOU	1,459,300	115,068,968	3,008	485,140	0.0789
61	3C General Power Service--TOU	285,886	28,254,992	1,034	276,485	0.0988
62	3D Pilot Municipalities & Counties General Power--TOU	94,332	7,208,996	152	620,605	0.0764
63	3E Pilot Municipalities & Counties General Power--TOU	23,340	2,521,599	80	291,750	0.1080
64	3F Non-Residential Charging Station-Pilot	6,515	572,872	12	542,893	0.0879
65	4B Large Power Svc--TOU	862,780	54,720,068	156	5,530,641	0.0634
66	5B Industrial Power Svc--TOU	14,453	1,395,056	1	14,453,000	0.0965
67	6 Private Area Lighting Svc	10,094	1,807,076			0.1790
68	9/11 - Industrials Power Service	410,684	27,704,479	1	410,684,000	0.0675
70	Fuel Adjustment Clause	—	142,527,979			
71	Energy Efficiency	—	19,059,692			
72	Renewable Rate Rider	—	25,812,374			
73	Transportation Electrification Program	—	7,225,581	—	—	—
74	Commercial and Industrial Sales Billed	6,525,592	628,888,466	58,676	111,214	0.0964
75	Commercial and Industrial Sales Unbilled	(11,054)	(2,099,866)			
76	Commercial and Industrial Sales Total	6,514,538	626,788,600	58,676	111,026	0.0962
	Public Street and Highway Lighting Sales					

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of 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 each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
77	20 Street & Floodlights	30,886	4,907,485	276	111,906	0.1589
78	2A Small Power Service	2,601	371,498	470	5,534	0.1428
79	2B Small Power Service--TOU	12	1,326	2	6,000	0.1105
80	6 Private Area Lighting Svc	—	43,132	—		
81	Fuel Adjustment Clause		742,351	—		
82	Energy Efficiency		41,529	—		
83	Transportation Electrification Program		3,002	—		
84	Renewable Rate Rider		338,063	—		
85	Public Street and Highway Lighting Sales Billed	33,499	6,448,386	748	44,785	0.1925
86	Public Street and Highway Lighting Sales Unbilled					
87	Public Street and Highway Lighting Sales Total	33,499	6,448,386	748	44,785	0.1925
	Other Sales to Public Authorities					
88	11B Water & Sewage Pump--TOU	176,376	9,229,286	147	1,199,837	0.0523
89	14B Large Svc for Mining	—	—	—		
90	2A Small Power Service	1,140	128,294	78	14,615	0.1125
91	2B Small Power Service--TOU	162	17,958	6	27,000	0.1109
92	3B General Power Service--TOU	252	32,571	1	252,000	0.1293
93	3C General Power Service--TOU	534	59,211	3	178,000	0.1109
94	3D Pilot Municipalities & Counties General Power--TOU	7,165	481,535	10	716,500	0.0672
95	3E Pilot Municipalities & Counties General Power--TOU	(21)	41,469	2	(10,500)	-1.9747
96	4B Large Power Svc--TOU	—	—	—		
97	Fuel Adjustment Clause		5,316,206	—		
98	Energy Efficiency		688,781	—		
99	Transportation Electrification Program		21,166			
100	Renewable Rate Rider		1,292,117	—		
101	Other Sales to Public Authorities Billed	185,608	17,308,594	247	751,449	0.0933
102	Other Sales to Public Authorities Unbilled					
103	Other Sales to Public Authorities Total	185,608	17,308,594	247	751,449	0.0933
	Sales to Railroads and Railways					
104	Sales to Railroads and Railways Billed					
105	Sales to Railroads and Railways Unbilled					
106	Sales to Railroads and Railways Total	—	—	—	—	0.0000
	Interdepartmental Sales					
107	Interdepartmental Sales Billed					
108	Interdepartmental Sales Unbilled					
109	Interdepartmental Sales Total	—	—	—	—	0.0000
	Total Sales					
110	TOTAL Billed	10,069,144	1,196,567,744	556,585	18,091	0.1188
111	Total Unbilled Rev.(See Instr. 6)	(23,691)	(4,458,561)	—		
112	TOTAL	10,045,453	1,192,109,183	556,585	18,048	0.1187

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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)	Actual Demand (MW) Average Monthly CP Demand (f)
1	AEPC - Arizona Electric Power Co-operative	SF	M			
2	APS - Arizona Public Service Company	SF	L			
3	ARON - J. Aron and Company	SF	L			
4	ATOP - Altop Energy Trading LLC	SF	L			
5	AVRN - Avangrid Power, LLC	SF	A			
6	AZPS - Arizona Public Service Company	OS	D			
7	BEPC - Basin Electric Power Cooperative	SF	L			
8	BHP - Black Hills Power	SF	L			
9	BPEC - BP Energy Company	SF	L			
10	BURB - Burbank, City of	SF	L			
11	CALP - Calpine Energy Services, L.P.	SF	L			
12	CAP - Central Arizona Water Conservation District	SF	L			
13	CCG - Constellation Energy Generation, LLC	SF	A			
14	CEI - Citigroup Energy Inc.	SF	A			
15	CONC - ConocoPhillips Company	SF	L			
16	CORP - Shell Energy North America (US), L.P.	SF	L			
17	CRSPM - Western Area Power Administration - CRSP	SF	L			
18	CSUM - Colorado Springs Utilities	SF	L			
19	DEAA - Arlington valley, LLC	OS	D			
20	DYNP - Dynasty Power Inc	SF	L			
21	EAGL - EDF Trading North America	SF	A			
22	EEMU - CP Energy Marketing (US) Inc.	OS	D			
23	EEMU - CP Energy Marketing (US) Inc.	SF	L			
24	ENKP - Energy Keepers, Inc	SF	L			
25	EPE - El Paso Electric Company	OS	D			
26	EPEC - El Paso Electric Company	SF	L			
27	FEUS - Farmington, City of	SF	L			
28	GPM - Guzman Energy, LLC	SF	L			
29	GRID	OS	D			
30	HGC - New Harquahala Generating Company LLC	OS	D			

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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 (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
25,053	—	493,006	—	493,006	1
42,876	—	1,749,479	—	1,749,479	2
400	—	16,800	—	16,800	3
17,171	—	746,449	—	746,449	4
6,000	—	309,400	—	309,400	5
118	—	4,761	—	4,761	6
—	—	—	—	—	7
7,282	—	128,984	—	128,984	8
7,363	—	229,694	—	229,694	9
1,200	—	55,540	—	55,540	10
44	—	1,695	—	1,695	11
46,459	—	842,541	—	842,541	12
3,549	—	136,893	—	136,893	13
55,173	—	1,789,507	—	1,789,507	14
11,055	—	214,243	—	214,243	15
7,640	—	237,694	—	237,694	16
15,054	—	473,736	—	473,736	17
40	—	1,950	—	1,950	18
312	—	9,853	—	9,853	19
43,556	—	1,413,833	—	1,413,833	20
5,241	—	177,352	—	177,352	21
(28)	—	(1,532)	—	(1,532)	22
82,306	—	1,625,783	—	1,625,783	23
29	—	1,189	—	1,189	24
17	—	514	—	514	25
4,087	—	131,407	—	131,407	26
29	—	580	—	580	27
70,556	—	2,445,467	—	2,445,467	28
153	—	5,029	—	5,029	29
—	—	(15)	—	(15)	30

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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)	Actual Demand (MW) Average Monthly CP Demand (f)
31	IID - Imperial Irrigation District	OS	D			
32	IIDM - Imperial Irrigation District	SF	L			
33	LAWM - Los Angeles Wholesale Marketing	SF	L			
34	MAG - MAG Energy Solutions Inc.	SF	L			
35	MCPI - Macquarie Energy, LLC	SF	L			
36	MEAI - Mercuria Energy America, Inc.	SF	L			
37	MID - Modesto Irrigation District	SF	L			
38	MSCG - Morgan Stanley Capital Group, Inc.	SF	A			
39	NVPM - NV Energy	OS	D			
40	NVPM - NV Energy	SF	L			
41	P66T - Phillips 66 Energy Trading LLC.	SF	L			
42	PAC - PacifiCorp	OS	D			
43	PAC - PacifiCorp	SF	L			
44	PSCM - Public Service Company of Colorado	SF	L			
45	PSEM - Puget Sound Energy Inc.	SF	L			
46	PWX - Powerex	SF	L			
47	REMC - Rainbow Energy Marketing Corporation	OS	N			
48	REMC - Rainbow Energy Marketing Corporation	SF	L			
49	SCHY - Samchully Power and Utilities	OS	B			
50	SMUD - Sacramento Municipal Utility District	SF	L			
51	SRP - Salt River Project	OS	D			
52	SRPM - Salt River Project	SF	L			
53	TCES - TransCanada Energy Sales Ltd.	SF	L			
54	TEA - The Energy Authority	OS	N			
55	TEA - The Energy Authority	SF	L			
56	TEMC - TransAlta Energy Marketing (US) Inc.	SF	L			
57	TEPC - Tucson Electric Power Company	OS	D			
58	TEPM - Tucson Electric Power	OS	B			
59	TEPM - Tucson Electric Power	SF	L			
60	TNSK - Tenaska Power Services Co.	SF	L			

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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 (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
46	—	2,263	—	2,263	31
810	—	36,800	—	36,800	32
2,000	—	54,480	—	54,480	33
6,081	—	214,005	—	214,005	34
11,227	—	531,180	—	531,180	35
3,748	—	133,244	—	133,244	36
3,200	—	93,400	—	93,400	37
20,779	—	659,335	—	659,335	38
43	—	1,281	—	1,281	39
640	—	57,100	—	57,100	40
75,016	—	2,905,177	—	2,905,177	41
71	—	2,908	—	2,908	42
13,548	—	707,110	—	707,110	43
2,804	—	86,050	—	86,050	44
349	—	3,785	—	3,785	45
89,172	—	581,249	—	581,249	46
1,542	—	19,110	—	19,110	47
20,471	—	526,527	—	526,527	48
—	—	67	—	67	49
7,625	—	187,446	—	187,446	50
61	—	2,587	—	2,587	51
962	—	72,293	—	72,293	52
450	—	28,350	—	28,350	53
42	—	210	—	210	54
31,631	—	920,179	—	920,179	55
12,922	—	440,222	—	440,222	56
256	—	10,656	—	10,656	57
—	—	67	—	67	58
8,047	—	394,915	—	394,915	59
39,551	—	1,230,622	—	1,230,622	60

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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 Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
61	TSPM - Tri-State Generation and Transmission	SF	L			
62	UMPA - Utah Municipal Power Agency	SF	L			
63	UNSE - UNS Electric, Inc.	SF	L			
64	WALC - Western Area Pwr Admin. - Lower Colorado	OS	D			
65	PCI - CAISO (MRTU)	OS	P			
66	PCI - CAISO (EESC)	OS	Q			
67	PCI - CAISO (PRSC)	OS	Q			
68	SJ Usage/Recovery	AD	C			
69	OTHER	AD	C			
70						
71	Subtotal RQ			—	—	—
72	Subtotal non-RQ			—	—	—
73	Total			—	—	—

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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 (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
7,839	—	241,778		241,778	61
9,645	—	502,373	—	502,373	62
4,064		203,160	—	203,160	63
26		1,157	—	1,157	64
433,384		15,396,169		15,396,169	65
1,589,882		30,460,751		30,460,751	66
1,204,223		27,737,624		27,737,624	67
2,947		76,652		76,652	68
(30)		(9,452)		(9,452)	69
				—	70
—	—		—	—	71
4,057,809	—	97,754,662	—	97,754,662	72
4,057,809	—	97,754,662	—	97,754,662	73

FOOTNOTE DATA

Page 310, Row 1, Column (a)

A. Sales of Short Term Firm transaction, ISDA Master Agreement.
B. Settlement of Ancillary Energy Paybacks at the Luna Energy Facility
C. Adjustments consisting of write offs and true ups
D. Emergency assistance provided under the Southwest Reserve Sharing Group Rate (SRSG) Schedule FERC No. 1
E. Not Used
F. Not Used
G. Not Used
H. Not Used
I. Not Used
J. Not Used
K. Not Used
L. Sales of Short Term Firm transactions, WSPP Rate Schedule FERC No. 6
M. Sales of Short Term Firm transactions, EEI Master Agreement
N. Sales of Short Term Non-firm transactions, WSPP Rate Schedule FERC No. 6
O. Not Used
P. Not Used
Q. Not Used

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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	3,212,860	3,849,475
5	(501) Fuel	78,060,674	82,022,646
6	(502) Steam Expenses	6,454,200	3,157,329
7	(503) Steam from Other Sources	—	—
8	(Less) (504) Steam Transferred-Cr.	—	—
9	(505) Electric Expenses	1,172,565	1,206,202
10	(506) Miscellaneous Steam Power Expenses	2,185,864	1,995,964
11	(507) Rents	221,802	218,896
12	(509) Allowances	565,672	—
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	91,873,637	92,450,512
14	Maintenance		
15	(510) Maintenance of Supervision and Engineering	674,204	660,548
16	(511) Maintenance of Structures	3,193,002	2,799,378
17	(512) Maintenance of Boiler Plant	6,192,403	7,684,855
18	(513) Maintenance of Electric Plant	5,867,418	1,623,227
18.1	(513.1) Maintenance of Computer Hardware	38,718	—
18.2	(513.2) Maintenance of Computer Software	—	—
18.3	(513.3) Maintenance of Communication Equipment	—	—
19	(514) Maintenance of Miscellaneous Steam Plant	977,211	668,041
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	16,942,956	13,436,049
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	108,816,593	105,886,561
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	6,680,617	6,242,806
25	(518) Fuel	16,670,741	19,759,103
26	(519) Coolants and Water	5,538,377	5,162,929
27	(520) Steam Expenses	2,535,713	2,366,696
28	(521) Steam from Other Sources	—	—
29	(Less) (522) Steamed Transferred-Cr.	—	—
30	(523) Electric Expenses	3,676,362	3,143,337
31	(524) Miscellaneous Nuclear Power Expenses	10,763,521	11,700,954
32	(525) Rents	68,412	967,757
33	TOTAL Operation (Enter Total of lines 24 thru 32)	45,933,743	49,343,582
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	1,108,189	2,558,808
36	(529) Maintenance of Structures	714,064	853,157
37	(530) Maintenance of Reactor Plant Equipment	3,140,309	3,704,665
38	(531) Maintenance of Electric Plant	4,916,246	4,373,654
39	(532) Maintenance of Miscellaneous Nuclear Plant	861,121	1,143,602
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	10,739,929	12,633,886
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	56,673,672	61,977,468
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)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	—	—
54	(542) Maintenance of Structure	—	—
55	(543) Maintenance of Reservoirs, Dams, and Waterways	—	—
56	(544) Maintenance of Electric Plant	—	—
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)	—	—
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	5,008,466	5,699,703
63	(547) Fuel	36,663,741	28,598,689
64	(548) Generation Expenses	—	5,669
64.1	(548.1) Operation of Energy Storage Equipment	—	—
65	(549) Miscellaneous Other Power Generation Expenses	97,910	1,775,586
66	(550) Rents	—	—
67	TOTAL Operation (Enter Total of lines 62 thru 66)	41,770,117	36,079,647
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	—	—
70	(552) Maintenance of Structures	1,186,063	1,017,195
71	(553) Maintenance of Generating and Electric Plant	9,624,675	10,847,499
71.1	(553.1) Maintenance of Energy Storage Equipment	—	5,714
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	—	—
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	10,810,738	11,870,408
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	52,580,855	47,950,055
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	345,424,533	282,482,863
76.1	(555.1) Power Purchased for Storage Operations	70,980,213	26,488,830
77	(556) System Control and Load Dispatching	6,410,471	5,695,655
78	(557) Other Expenses	231,180	189,782
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	423,046,397	314,857,130
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	1,859,442	—
79.6	(558.4) Rents	—	—
79.7	TOTAL Operation (Enter Total of lines 79.3 thru 79.6)	1,859,442	—
79.8	Maintenance		
79.9	(558.6) Maintenance Supervision and Engineering	—	—
79.10	(558.7) Maintenance of Solar Panels, Structures, and Equipment	1,904,852	—
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)	1,904,852	—
79.16	TOTAL Power Production Expenses-Solar (total of lines 79.7 & 79.15)	3,764,294	—
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74, 79, 79.16,	644,881,811	530,671,214
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	(598,801)	2,373,623
84			
85	(561.1) Load Dispatch-Reliability	(14,341)	49,872
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	334,185	437,279
87	(561.3) Load Dispatch-Transmission Service and Scheduling	474,626	595,088

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
88	(561.4) Scheduling, System Control and Dispatch Services	—	—
89	(561.5) Reliability, Planning and Standards Development	—	—
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	1,336,605	1,616,678
94	(563) Overhead Lines Expenses	227,275	146,630
95	(564) Underground Lines Expenses	—	—
96	(565) Transmission of Electricity by Others	24,606,700	18,138,797
97	(566) Miscellaneous Transmission Expenses	3,577,703	3,991,174
98	(567) Rents	16,410,672	14,987,542
99	TOTAL Operation (Enter Total of lines 83 thru 98)	46,354,624	42,336,683
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	27,111	22,658
102	(569) Maintenance of Structures	—	—
103	(569.1) Maintenance of Computer Hardware	—	—
104	(569.2) Maintenance of Computer Software	1,323,654	—
105	(569.3) Maintenance of Communication Equipment	—	—
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	—	—
107	(570) Maintenance of Station Equipment	3,909,580	3,442,161
107.1	(570.1) Maintenance of Energy Storage Equipment	—	—
108	(571) Maintenance of Overhead Lines	783,247	953,588
109	(572) Maintenance of Underground Lines	—	—
110	(573) Maintenance of Miscellaneous Transmission Plant	7,167	8,812
111	TOTAL Maintenance (Total of lines 101 thru 110)	6,050,759	4,427,219
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	52,405,383	46,763,902
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	—	—

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
131.10	(578.2) Maintenance of Energy Storage Equipment and Structures	67,481	—
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)	67,481	—
131.16	TOTAL Energy Storage Expenses (Total of 131.7 and 131.15)	67,481	—
132	5. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,799,023	1,465,363
135	(581) Load Dispatching	—	—
136	(582) Station Expenses	1,047,307	1,019,300
137	(583) Overhead Line Expenses	3,517,862	3,527,761
138	(584) Underground Line Expenses	961,541	800,688
139	(585) Street Lighting and Signal System Expenses	—	—
140	(586) Meter Expenses	3,501,993	3,648,333
141	(587) Customer Installations Expenses	—	—
142	(588) Miscellaneous Expenses	9,168,730	8,858,223
143	(589) Rents	751,060	846,376
144	TOTAL Operation (Enter Total of lines 134 thru 143)	20,747,516	20,166,044
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,013,678	1,082,213
147	(591) Maintenance of Structures	38,341	52,518
148	(592) Maintenance of Station Equipment	1,714,694	1,609,687
148.1	(592.2) Maintenance of Computer Hardware	—	—
148.2	(592.3) Maintenance of Computer Software	727,408	—
148.3	(592.4) Maintenance of Communication Equipment	—	—
149	(593) Maintenance of Overhead Lines	8,685,257	7,548,165
150	(594) Maintenance of Underground Lines	2,490,515	2,122,188
151	(595) Maintenance of Line Transformers	—	66
152	(596) Maintenance of Street Lighting and Signal Systems	981,140	693,476
153	(597) Maintenance of Meters	679,271	668,051
154	(598) Maintenance of Miscellaneous Distribution Plant	—	—
155	TOTAL Maintenance (Total of lines 146 thru 154)	16,330,304	13,776,364
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	37,077,820	33,942,408
157	6. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	(264,661)	(379,562)
160	(902) Meter Reading Expenses	8,429,737	8,219,098
161	(903) Customer Records and Collection Expenses	12,130,217	11,847,158
162	(904) Uncollectible Accounts	4,494,535	4,059,071
163	(905) Miscellaneous Customer Accounts Expenses	—	—
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	24,789,828	23,745,765
165	7. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	39,859	146,144
168	(908) Customer Assistance Expenses	1,410,723	1,341,558
169	(909) Informational and Instructional Expenses	107,995	160,851
170	(910) Miscellaneous Customer Service and Informational Expenses	—	—
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	1,558,577	1,648,553

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
172	8. SALES EXPENSES		
173	Operation		
174	(911) Supervision	—	—
175	(912) Demonstrating and Selling Expenses	4,726,187	6,146,988
176	(913) Advertising Expenses	—	339,746
177	(916) Miscellaneous Sales Expenses	—	—
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	4,726,187	6,486,734
179	9. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	48,569,722	52,195,966
182	(921) Office Supplies and Expenses	7,145,207	15,036,979
183	(Less) (922) Administrative Expenses Transferred-Credit	(18,021,555)	(17,806,554)
184	(923) Outside Services Employed	19,920,244	18,240,211
185	(924) Property Insurance	3,312,606	2,966,738
186	(925) Injuries and Damages	10,404,814	7,033,257
187	(926) Employee Pensions and Benefits	88,375,650	18,460,660
188	(927) Franchise Requirements	—	—
189	(928) Regulatory Commission Expenses	46,742,257	42,461,100
190	(929) (Less) Duplicate Charges-Cr.	—	—
191	(930.1) General Advertising Expenses	—	—
192	(930.2) Miscellaneous General Expenses	14,017,364	13,587,311
193	(931) Rents	396,982	357,341
194	TOTAL Operation (Enter Total of lines 181 thru 193)	256,906,401	188,146,117
195	Maintenance		
196	(935) Maintenance of General Plant	2,516,555	2,360,533
196.1	(935.1) Maintenance of Computer Hardware	—	—
196.2	(935.2) Maintenance of Computer Software	6,154,129	—
196.3	(935.3) Maintenance of Communication Equipment	—	—
196.4	TOTAL Maintenance (Enter Total of lines 196 thru 196.3)	8,670,684	2,360,533
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196.4)	265,577,085	190,506,650
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112,	1,031,084,172	833,765,226

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
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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 Classification	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	AEPC - Arizona Electric Power Co-operative	SF	U			
2	APS - Arizona Public Service Company	SF	K			
3	ARES - Arroyo Energy Storage, LLC	LU	AI			
4	ARSO -Arroyo Solar, LLC	LU	AB			
5	ATOP - Altop Energy Trading LLC	SF	K			
6	ATR - Atrisco Energy Storage LLC, a subsidary of	LU	AI			
7	ATRS - Atrisco Solar PPA	LU	AB			
8	AVRN - Avangrid Power, LLC	SF	V			
9	AZPS - Arizona Public Service Company	OS	F			
10	BHP - Black Hills Power	SF	K			
11	BPEC - BP Energy Company	SF	K			
12	CALP - Calpine Energy Services, L.P.	SF	K			
13	CAP - Central Arizona Water Conservation District	SF	K			
14	CCG - Constellation Energy Generation, LLC	SF	V			
15	CEI - Citigroup Energy Inc.	SF	V			
16	CMA - Casa Mesa	LU	I			
17	CONC - ConocoPhillips Company	OS	H			
18	CONC - ConocoPhillips Company	SF	K			
19	CORP - Shell Energy North America (US), L.P.	SF	K			
20	CRSPM - Western Area Power Administration - CRSP	SF	K			
21	CYRQ-LDG - Lightning Dock Geothermal	LU	AE			
22	DRW Energy Trading LLC	SF	K			

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
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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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatt hours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatt hours 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 totaled 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 ($)	Total (j+k+l) of Settlement ($)	
(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
281,843					11,351,427	—	11,351,427	1
128,937					5,167,835	—	5,167,835	2
				13,264,750		—	13,264,750	3
734,024					11,775,706	—	11,775,706	4
18,500					1,922,617	—	1,922,617	5
				32,980,813		—	32,980,813	6
740,517					17,191,126	—	17,191,126	7
600					19,500	—	19,500	8
64					3,548	—	3,548	9
3,633					141,619	—	141,619	10
22,748					918,456	—	918,456	11
6,400					250,776	—	250,776	12
6,457					274,409	—	274,409	13
24,800					2,415,520	—	2,415,520	14
38,809					3,088,252	—	3,088,252	15
180,485					5,068,914	—	5,068,914	16
15					495	—	495	17
5,883					243,342	—	243,342	18
72,790					3,152,238	—	3,152,238	19
7,270					189,170	—	189,170	20
58,098					6,146,234	—	6,146,234	21
7,600					188,224	—	188,224	22

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
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PURCHASED POWER (Account 555)
(Including power exchanges)

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)
23	DSWM - Western Area Power Admin-DSW	SF	K			
24	DYNP - Dynasty Power Inc	SF	K			
25	EAGL - EDF Trading North America	SF	V			
26	EEMU - CP Energy Marketing (US) Inc.	SF	K			
27	ENKP - Energy Keepers, Inc	SF	K			
28	EPE - El Paso Electric Company	OS	F			
29	EPEC - El Paso Electric Company	SF	K			
30	FPLE - FPL Energy American Wind LLC	LU	I			
31	GLND - City of Glendale	SF	K			
32	GPM - Guzman Energy, LLC	SF	K			
33	GRID	OS	F			
34	IID - Imperial Irrigation District	OS	F			
35	IIDM - Imperial Irrigation District	OS	G			
36	IUSA - Avangrid Inc.	LU	I			
37	JCS1 - Jicarilla Solar 1, LLC	LU	AB			
38	JCS2 - Jicarilla Solar 2, LLC	LU	AB			
39	JCSG1 - Jicarilla Storage 1	LU	AI			
40	LAWM - Los Angeles Wholesale Marketing	SF	K			
41	MAG - MAG Energy Solutions Inc.	SF	K			
42	MCPI - Macquarie Energy, LLC	SF	K			
43	MEAI - Mercuria Energy America, Inc.	SF	K			
44	MLCI - Merrill Lynch Commodities, Inc.	SF	V			
45	MSCG - Morgan Stanley Capital Group, Inc.	SF	V			
46	NMRD - NM Renewable Development LLC	LU	AB			
47	NVPM - NV Energy	OS	F			
48	NVPM - NV Energy	SF	K			
49	P66T - Phillips 66 Energy Trading LLC.	SF	K			
50	PAC - PacifiCorp	OS	H			
51	PAC - PacifiCorp	SF	K			
52	PSEM - Puget Sound Energy Inc.	SF	K			
53	PWX - Powerex	SF	K			
54	Quail Ranch Solar	LU	AB			
55	REMC - Rainbow Energy Marketing Corporation	SF	K			
56	RMW - Red Mesa Wind	LU	I			
57	RT66 - Route 66 Solar Energy Center, LLC	LU	AB			
58	RT66 - Route 66 Solar Energy Center, LLCES	LU	AI			
59	SGPM - Sempra Gas and Power Marketing, LLC	SF	K			
60	SJES - San Juan ESA (Battery)	LU	AI			
61	SJS - San Juan Solar PPA	LU	AB			
62	SRES - Sky Ranch Energy Storage	LU	AI			
63	SRES - Sky Ranch Energy StorageII	LU	AI			
64	SRP - Salt River Project	OS	F			
65	SRPM - Salt River Project	SF	K			
66	SRSO - Sky Ranch Solar, LLC	LU	AB			
67	TAGE- TAG Energy Storage	LU	AI			
68	TAGS- TAG Solar	LU	AB			
69	TCES - TransCanada Energy Sales Ltd.	SF	K			
70	TEA - The Energy Authority	OS	H			

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
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PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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 ($)	Total (j+k+l) of Settlement ($)	
(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
7,238					274,169	—	274,169	23
26,468					998,764	—	998,764	24
3,075					141,657	—	141,657	25
32,278					1,259,654	—	1,259,654	26
1,800					80,950	—	80,950	27
23					1,311	—	1,311	28
155,900					5,837,873	—	5,837,873	29
529,226					15,474,005	—	15,474,005	30
70					2,650	—	2,650	31
55,491					8,057,994	—	8,057,994	32
4					243	—	243	33
4					207	—	207	34
105					1,050	—	1,050	35
936,968					21,688,327	—	21,688,327	36
112,137					2,212,460	—	2,212,460	37
127,578					2,772,279	—	2,772,279	38
				2,551,323		—	2,551,323	39
8,328					303,059	—	303,059	40
42,368					1,847,822	—	1,847,822	41
10,000					413,350	—	413,350	42
71,780					2,849,886	—	2,849,886	43
1,200					66,608	—	66,608	44
64,278					6,592,125	—	6,592,125	45
501,166					15,044,158	—	15,044,158	46
67					3,835	—	3,835	47
5,376					193,110	—	193,110	48
159,689					10,002,737	—	10,002,737	49
260					6,400	—	6,400	50
90,409					3,706,860	—	3,706,860	51
25					1,050	—	1,050	52
600					29,750	—	29,750	53
31,528					557,963	—	557,963	54
306					3,040	—	3,040	55
184,170					6,267,672	—	6,267,672	56
128,302					3,846,539	—	3,846,539	57
				751,681		—	751,681	58
150					7,800	—	7,800	59
				12,217,680		—	12,217,680	60
509,542					15,914,550	—	15,914,550	61
—				3,822,171	1,274,057	—	5,096,228	62
				2,590,502		—	2,590,502	63
69					3,867	—	3,867	64
184,161					8,185,684	—	8,185,684	65
518,735					12,019,345	—	12,019,345	66
				2,391,236		—	2,391,236	67
183,992					4,554,806	—	4,554,806	68
300					19,950	—	19,950	69
15					401	—	401	70

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PURCHASED POWER (Account 555)
(Including power exchanges)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
71	TEA - The Energy Authority	SF	K			
72	TEMC - TransAlta Energy Marketing (US) Inc.	SF	K			
73	TEPC - Tucson Electric Power Company	OS	F			
74	TEPM - Tucson Electric Power	SF	K			
75	TNSK - Tenaska Power Services Co.	SF	K			
76	TSPM - Tri-State Generation and Transmission	SF	K			
77	UMPA - Utah Municipal Power Agency	SF	K			
78	UNSE - UNS Electric, Inc.	SF	K			
79	VEF - Valencia Power, LLC	LU	T			
80	VITOL - Vitol Inc.	SF	K			
81	WALC - Western Area Pwr Admin. - Lower Colorado	OS	R			
82	WALC - Western Area Pwr Admin. - Lower Colorado	OS	F			
83	Misc Adjustments	AD	M			
84	Renewable Rider	OS	AF			
85	Deferred Energy	OS	O			
86	Freeport	LU	AD			
87	Cogen Small Power	OS	AC			
88	Economic Benefit	OS	R			
89	Valencia - Other	LU	T			
90	PCI - CAISO (MRTU)	OS	P			
91	PCI - CAISO (PRSC)	OS	Q			
92	PCI - CAISO (EESC)	OS	Q			
93	Damages	OS	AG			
94	APS-Arizona Public Service_Four Corners	EX	Z			
95	APS-Arizona Public Service_Palo Verde	EX	Z			
96	Area Exchanges	EX	Z			
97	Total					

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
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PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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 ($)	Total (j+k+l) of Settlement ($)	
(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
43,238					1,751,771	—	1,751,771	71
1,691					84,367	—	84,367	72
22					1,223	—	1,223	73
63,387					2,469,649	—	2,469,649	74
16,414					700,328	—	700,328	75
7,626					376,309	—	376,309	76
200					14,000	—	14,000	77
1,400					45,614	—	45,614	78
147,132				9,797,295	13,409,046	—	23,206,341	79
5,800					247,812	—	247,812	80
10,745				192,245	215,766	—	408,011	81
12					696	—	696	82
—					25,837		25,837	83
—					11,517		11,517	84
—					316,382		316,382	85
410,684					23,876,840		23,876,840	86
564,049					4,157,866		4,157,866	87
—					237,632		237,632	88
—					781,626		781,626	89
67,811					3,666,024		3,666,024	90
1,168,460					12,998,267		12,998,267	91
1,585,954					49,291,053		49,291,053	92
—					(864,000)		(864,000)	93
		1,798	2,387				—	94
		3,971	2,133				—	95
		154,707	155,102				—	96
11,119,279	—	160,476	159,622	80,559,696	335,845,050	—	416,404,746	97

Page 326, Row 1, Column (a)

A. Not Used
B. Not Used
C. Not Used
D. Not Used
E. Not Used
F. Emergency Assistance received under the Southwest Reserve Sharing Group Rate (SRSG) agreement
G. Unit contingent purchases as provided for under Western Power Pool agreement
H. WSPP Non-Firm
I. Wind Generation purchases
J. Not Used
K. Short Term firm purchases on WSPP
L. Not Used
M. Not Used
N. Not Used
O. Not Used
P. Not Used
Q. Not Used
R. Semi-annual refund from Western Area Lower Colorado for service provided to Pueblos
S. Not Used
T. Transactions with Valencia Energy Facility treated as a purchased power agreement
U. Short Term firm purchases EEI agreement
V. Short Term firm purchases ISDA agreement
W. Not Used
X. Not Used
Y. Not Used
Z. Energy Exchanges
AA. Not Used
AB. Solar Generation Purchases
AC. Not Used
AD. Not Used
AE. Geothermal Lighting Dock PPA
AF. Not Used
AG. Not Used
AH. Not Used
AI. Energy Storage Agreement
AJ. Not Used

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	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 Classifi-cation (d)
1	Aragonne Wind, LLC (D)	Public Service Co. of NM	Arizona Public Service Co	LFP
2	Aragonne Wind, LLC (E)	Southwestern Public Service Co.	Arizona Public Service Co	LFP
3	Arizona Electric Power Cooperative (J)	El Paso Electric Co.	Tucson Electric Power Co	LFP
4	Arizona Public Service Co (AC)	Public Service Co. of NM	Public Service Co. of NM	NF
5	Arizona Public Service Co (AC,AF)	Public Service Co. of NM	Public Service Co. of NM	SFP
6	Avangrid Renewables (AC)	Southwestern Public Service Co.	Arizona Public Service Co	NF
7	Broadview Energy JN, LLC (K,L)	Southwestern Public Service Co.	Arizona Public Service Co	LFP
8	Broadview Energy JN, LLC (K,L)	Public Service Co. of NM	Arizona Public Service Co	LFP
9	Broadview Energy JN, LLC (AC)	Public Service Co. of NM	Arizona Public Service Co	NF
10	Broadview Energy JN, LLC (AC)	Public Service Co. of NM	Arizona Public Service Co	NF
11	Broadview Energy JN, LLC (AC)	Southwestern Public Service Co.	Arizona Public Service Co	NF
12	Broadview Energy JN, LLC (AC)	Southwestern Public Service Co.	Public Service Co. of NM	NF
13	Broadview Energy KW, LLC (M)	Southwestern Public Service Co.	Arizona Public Service Co	LFP
14	Broadview Energy KW, LLC (AC)	Southwestern Public Service Co.	Arizona Public Service Co	NF
15	Broadview Energy KW, LLC (AC)	Southwestern Public Service Co.	Public Service Co. of NM	NF
16	Broadview Energy KW, LLC (AC)	Public Service Co. of NM	Arizona Public Service Co	NF
17	Broadview Energy KW, LLC (AC)	Public Service Co. of NM	Arizona Public Service Co	NF
18	City of Farmington Electric Utility (A)	Public Service Co of NM	Western Area Power Admin.	OLF
19	City of Gallup Electric Utility (R,AE)	Public Service Co of NM	City of Gallup Electric Utility	FNO
20	Clines Corners Wind Farm, LLC (AN,AO)	Public Service Co. of NM	Arizona Public Service Co	LFP
21	Clines Corners Wind Farm, LLC (AC)	Public Service Co. of NM	Arizona Public Service Co	NF
22	Clines Corners Wind Farm, LLC (AC)	Public Service Co. of NM	Arizona Public Service Co	NF
23	Clines Corners Wind Farm, LLC (AC)	Public Service Co. of NM	Public Service Co. of NM	NF
24	CP Energy Marketing Inc. (AC)	El Paso Electric Co.	Southwestern Public Service Co.	NF
25	Duran Mesa, LLC (AP)	Public Service Co. of NM	Arizona Public Service Co	LFP
26	Duran Mesa, LLC (AC)	Public Service Co. of NM	Arizona Public Service Co	NF
27	Duran Mesa, LLC (AC)	Public Service Co. of NM	Arizona Public Service Co	NF
28	Duran Mesa, LLC (AC)	Public Service Co. of NM	Public Service Co. of NM	NF
29	Dynasty Power Inc. (AC)	El Paso Electric Co.	Southwestern Public Service Co.	NF
30	Dynasty Power Inc. (AC)	Southwestern Public Service Co.	El Paso Electric Co.	NF
31	Dynasty Power Inc. (AC,AF)	Arizona Public Service Co	El Paso Electric Co.	SFP
32	Dynasty Power Inc. (AC,AF)	Public Service Co. of NM	Public Service Co. of NM	SFP
33	EL Cabo Wind, LLC (AC)	Southwestern Public Service Co.	Arizona Public Service Co	NF
34	EL Cabo Wind, LLC (N,O,P,Q)	Southwestern Public Service Co.	Arizona Public Service Co	LFP
35	El Paso Electric Company (F)	Arizona Public Service Co	El Paso Electric Co.	LFP
36	El Paso Electric Company (AC)	Arizona Public Service Co	El Paso Electric Co.	NF
37	El Paso Electric Company (AC)	El Paso Electric Co.	Arizona Public Service Co	NF
38	El Paso Electric Company (AC)	El Paso Electric Co.	El Paso Electric Co.	NF

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)(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 megawatt hours received and delivered.

FERC Rate Schedule of Tariff Number	Point of Receipt (Substation or Other Designation)	Point of Delivery (Substation or Other Designation)	Billing Demand (MW)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received	MegaWatt Hours Delivered	
(e)	(f)	(g)	(h)	(i)	(j)	
Tariff Vol. 6	Guadalupe	Four Corners	145	426,844	426,844	1
Tariff Vol. 6	Blackwater	Four Corners	55	69,684	69,684	2
Tariff Vol. 6	Hidalgo	Greenlee	40	68,441	68,441	3
Tariff Vol. 6	Guadalupe	San Juan		1	1	4
Tariff Vol. 6	Albuquerque	San Juan		—	—	5
Tariff Vol. 6	Clines Corners	Four Corners		—	—	6
Tariff Vol. 6	Blackwater	Four Corners	167	444,685	444,685	7
Tariff Vol. 6	Guadalupe	Four Corners		—	—	8
Tariff Vol. 6	San Juan	Four Corners		—	—	9
Tariff Vol. 6	Western Spirit	Four Corners		—	—	10
Tariff Vol. 6	Blackwater	Four Corners		48,959	48,959	11
Tariff Vol. 6	Blackwater	San Juan		89	89	12
Tariff Vol. 6	Blackwater	Four Corners	130	496,381	496,381	13
Tariff Vol. 6	Blackwater	Four Corners		535	535	14
Tariff Vol. 6	Blackwater	San Juan		32,897	32,897	15
Tariff Vol. 6	San Juan	Four Corners		805	805	16
Tariff Vol. 6	Western Spirit	Four Corners		—	—	17
51	San Juan	Shiprock	43	10,353	10,353	18
Tariff Vol. 6	San Juan	Shiprock		104,314	104,314	19
Tariff Vol. 6	Western Spirit	Four Corners	243	447,863	447,863	20
Tariff Vol. 6	San Juan	Four Corners		80	80	21
Tariff Vol. 6	Western Spirit	Four Corners		10,353	10,353	22
Tariff Vol. 6	Western Spirit	San Juan		104,234	104,234	23
Tariff Vol. 6	Amrad	Eddy		—	—	24
Tariff Vol. 6	Western Spirit	Four Corners	63	244,483	244,483	25
Tariff Vol. 6	San Juan	Four Corners		313	313	26
Tariff Vol. 6	Western Spirit	Four Corners		4,301	4,301	27
Tariff Vol. 6	Western Spirit	San Juan		25,336	25,336	28
Tariff Vol. 6	Amrad	Eddy		48	48	29
Tariff Vol. 6	Eddy	Amrad		150	150	30
Tariff Vol. 6	Four Corners	West Mesa		115	115	31
Tariff Vol. 6	San Juan	Ojo		22	22	32
Tariff Vol. 6	Clines Corners	Four Corners		5,624	5,624	33
Tariff Vol. 6	Clines Corners	Four Corners	269	1,042,074	1,042,074	34
Tariff Vol. 6	Four Corners	West Mesa	104	39,892	39,892	35
Tariff Vol. 6	Four Corners	West Mesa		436	436	36
Tariff Vol. 6	West Mesa	Four Corners		445	445	37
Tariff Vol. 6	Hidalgo	Hidalgo		120	120	38

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (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.
7,324,432	—		7,324,432	1
2,778,233	—		2,778,233	2
2,020,533	73,162		2,093,695	3
737			737	4
1,456			1,456	5
8,367	53		8,420	6
8,276,554	482,572	—	8,759,126	7
159,173			159,173	8
18			18	9
1,945			1,945	10
5,343			5,343	11
535			535	12
6,566,733	357,656		6,924,389	13
6,602			6,602	14
45			45	15
16,375			16,375	16
1,891			1,891	17
57,888		—	57,888	18
1,518,380	112,362	119,409	1,750,151	19
10,113,552	491,536		10,605,088	20
726			726	21
191,004	99,530		290,534	22
532,213	31,079		563,292	23
54	—		54	24
2,622,032	215,945		2,837,977	25
5,501			5,501	26
79,710			79,710	27
428,610			428,610	28
584	42		626	29
1,621	107		1,728	30
1,243	208		1,451	31
616			616	32
228,658			228,658	33
13,588,087	618,773		14,206,860	34
5,253,387	48,551		5,301,938	35
4,448			4,448	36
4,629			4,629	37
1,089	127		1,216	38

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

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 Classifi-cation (d)
39	El Paso Electric Company (AC)	El Paso Electric Co.	Public Service Co. of NM	NF
40	El Paso Electric Company (AC)	Public Service Co. of NM	El Paso Electric Co.	NF
41	El Paso Electric Company (AC)	Southwestern Public Service Co.	El Paso Electric Co.	NF
42	El Paso Electric Company (AC)	Tucson Electric Power Co	El Paso Electric Co.	NF
43	El Paso Electric Company (AC,AF)	Arizona Public Service Co	El Paso Electric Co.	SFP
44	El Paso Electric Company (AC,AF)	El Paso Electric Co.	Arizona Public Service Co	SFP
45	El Paso Electric Company (AC,AF)	El Paso Electric Co.	El Paso Electric Co.	SFP
46	El Paso Electric Company (AC,AF)	El Paso Electric Co.	Public Service Co. of NM	SFP
47	El Paso Electric Company (AC,AF)	Public Service Co. of NM	El Paso Electric Co.	SFP
48	El Paso Electric Company (AC,AF)	Salt River Project	Salt River Project	SFP
49	Grady Wind Energy Center, LLC (AA,AB)	Southwestern Public Service Co.	Arizona Public Service Co	LFP
50	Grady Wind Energy Center, LLC (AC,AF)	Public Service Co. of NM	Tucson Electric Power Co	SFP
51	Grady Wind Energy Center, LLC (AC,AF)	Public Service Co. of NM	Tucson Electric Power Co	SFP
52	Guzman Power Markets (AU)	Public Service Co. of NM	Public Service Co. of NM	LFP
53	Guzman Power Markets (AC)	Arizona Public Service Co	Arizona Public Service Co	NF
54	Guzman Power Markets (AC)	Arizona Public Service Co	Public Service Co. of NM	NF
55	Guzman Power Markets (AC)	Arizona Public Service Co	Public Service Co. of NM	NF
56	Guzman Power Markets (AC)	Public Service Co. of NM	Arizona Public Service Co	NF
57	Guzman Power Markets (AC)	Public Service Co. of NM	Arizona Public Service Co	NF
58	Guzman Power Markets (AC)	Public Service Co. of NM	Arizona Public Service Co	NF
59	Guzman Power Markets (AC)	Public Service Co. of NM	Public Service Co. of NM	NF
60	Guzman Power Markets (AC)	Public Service Co. of NM	Public Service Co. of NM	NF
61	Guzman Power Markets (AC)	Public Service Co. of NM	Public Service Co. of NM	NF
62	Guzman Power Markets (AC)	Public Service Co. of NM	Public Service Co. of NM	NF
63	Guzman Power Markets (AC)	Public Service Co. of NM	Public Service Co. of NM	NF
64	Guzman Power Markets (AC)	Tucson Electric Power Co	Public Service Co. of NM	NF
65	Guzman Power Markets (AC,AF)	Arizona Public Service Co	Public Service Co. of NM	SFP
66	Guzman Power Markets (AC,AF)	Arizona Public Service Co	Public Service Co. of NM	SFP
67	Guzman Power Markets (AC,AF)	Arizona Public Service Co	Public Service Co. of NM	SFP
68	Guzman Power Markets (AC,AF)	Public Service Co. of NM	Public Service Co. of NM	SFP
69	Guzman Power Markets (AC,AF)	Public Service Co. of NM	Public Service Co. of NM	SFP
70	Guzman Power Markets (AC,AF)	Public Service Co. of NM	Public Service Co. of NM	SFP
71	Guzman Power Markets (AC,AF)	Public Service Co. of NM	Public Service Co. of NM	SFP
72	Guzman Power Markets (AC,AF)	Public Service Co. of NM	Public Service Co. of NM	SFP
73	Guzman Power Markets (AC,AF)	Public Service Co. of NM	Public Service Co. of NM	SFP
74	High Lonesome Mesa (H,I)	Public Service Co. of NM	Arizona Public Service Co	LFP
75	Imperial Irrigation District (AC,AF)	Salt River Project	Arizona Public Service Co.	SFP
76	Jicarilla Apache Nation (S,AE)	Public Service Co of New Mexico	Jicarilla Apache Nation	FNO
77	Kit Carson Electric Coop (X,AE)	Guzman Renewable Energy Partners	Kit Carson Electric Cooperative	FNO
78	Leeward Renewable Energy Development (AS)	Southwestern Public Service Co.	Arizona Public Service Co	LFP
79	Los Alamos County Utilities (U,AE)	Los Alamos County Utilities	Los Alamos County Utilities	FNO
80	MAG Energy Solutions (AC)	El Paso Electric Co.	Arizona Public Service Co	NF
81	MAG Energy Solutions (AC)	El Paso Electric Co.	Public Service Co. of NM	NF
82	MAG Energy Solutions (AC)	Southwestern Public Service Co.	El Paso Electric Co.	NF
83	MAG Energy Solutions (AC,AF)	Arizona Public Service Co	Public Service Co. of NM	SFP
84	MAG Energy Solutions (AC,AF)	El Paso Electric Co.	Public Service Co. of NM	SFP
85	MAG Energy Solutions (AC,AF)	Southwestern Public Service Co.	El Paso Electric Co.	SFP
86	Navajo Tribal Utility Authority (V,AE)	Navajo Tribal Utility Authority	Navajo Tribal Utility Authority	FNO
87	Public Service Co. of NM (AC)	Public Service Co. of NM	El Paso Electric Co.	NF

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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

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 MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
Tariff Vol. 6	Picacho	Airport		6	6	39
Tariff Vol. 6	Airport	Picacho		3	3	40
Tariff Vol. 6	Eddy	Amrad		1,305	1,305	41
Tariff Vol. 6	Greenlee	Hidalgo		146	146	42
Tariff Vol. 6	Four Corners	West Mesa		1,452	1,452	43
Tariff Vol. 6	West Mesa	Four Corners		181	181	44
Tariff Vol. 6	Hidalgo	Hidalgo		12,057	12,057	45
Tariff Vol. 6	Picacho	Airport		31,900	31,900	46
Tariff Vol. 6	Airport	Picacho		1,055	1,055	47
Tariff Vol. 6	Palo Verde	Kyrene		80	80	48
Tariff Vol. 6	Blackwater	Four Corners	200	762,381	762,381	49
Tariff Vol. 6	San Juan	Coronado		4,514	4,514	50
Tariff Vol. 6	San Juan	Springerville		41,787	41,787	51
Tariff Vol. 6	Ojo	San Juan	26	3,135	3,135	52
Tariff Vol. 6	Four Corners	Four Corners		8,128	8,128	53
Tariff Vol. 6	Four Corners	Ojo		4,961	4,961	54
Tariff Vol. 6	Four Corners	San Juan		—	—	55
Tariff Vol. 6	Jicarilla	Four Corners		745	745	56
Tariff Vol. 6	Ojo	Four Corners		928	928	57
Tariff Vol. 6	San Juan	Four Corners		73	73	58
Tariff Vol. 6	Jicarilla	Ojo		—	—	59
Tariff Vol. 6	Jicarilla	San Juan		86,068	86,068	60
Tariff Vol. 6	Ojo	San Juan		7,136	7,136	61
Tariff Vol. 6	San Juan	Hogback		—	—	62
Tariff Vol. 6	San Juan	Ojo		6,242	6,242	63
Tariff Vol. 6	Springerville	San Juan		39	39	64
Tariff Vol. 6	Four Corners	Jicarilla		18	18	65
Tariff Vol. 6	Four Corners	Ojo		7,249	7,249	66
Tariff Vol. 6	Four Corners	San Juan		100	100	67
Tariff Vol. 6	Jicarilla	Ojo		238	238	68
Tariff Vol. 6	Jicarilla	San Juan		65,496	65,496	69
Tariff Vol. 6	Ojo	Jicarilla		—	—	70
Tariff Vol. 6	Ojo	San Juan		128	128	71
Tariff Vol. 6	San Juan	Jicarilla		40	40	72
Tariff Vol. 6	San Juan	Ojo		3,292	3,292	73
Tariff Vol. 6	Willard	Four Corners	100	282,093	282,093	74
Tariff Vol. 6	Palo Verde	West Wing		1,944	1,944	75
Tariff Vol. 6	San Juan	Shiprock		22,330	22,330	76
Tariff Vol. 6	San Juan	Shiprock		—	—	77
Tariff Vol. 6	Blackwater	Four Corners	35	—	—	78
Tariff Vol. 6	San Juan	Shiprock		—	—	79
Tariff Vol. 6	West Mesa	Four Corners		—	—	80
Tariff Vol. 6	West Mesa	San Juan		—	—	81
Tariff Vol. 6	Eddy	Amrad		—	—	82
Tariff Vol. 6	Four Corners	Ojo		705	705	83
Tariff Vol. 6	West Mesa	San Juan		—	—	84
Tariff Vol. 6	Eddy	Amrad		22,330	22,330	85
Tariff Vol. 6	San Juan	Shiprock		2,604	2,604	86
Tariff Vol. 6	Albuquerque	West Mesa		1,072	1,072	87

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
64			64	39
64			64	40
14,103	4,624		18,727	41
2,269	244		2,513	42
14,247	8,203		22,450	43
2,042			2,042	44
129,937	19,869		149,806	45
354,507	3,941		358,448	46
46,017	41,388		87,405	47
865	44		909	48
10,102,667	547,171		10,649,838	49
11,670			11,670	50
829,508			829,508	51
1,313,347	60,773		1,374,120	52
154			154	53
10,986	2,515		13,501	54
36			36	55
7,014			7,014	56
6,833			6,833	57
1,286			1,286	58
756			756	59
121,278			121,278	60
3,512			3,512	61
162			162	62
2,967			2,967	63
—	70		70	64
195			195	65
32,248	1,321		33,569	66
4,247	83		4,330	67
2,572			2,572	68
311,481			311,481	69
9	201		210	70
2,300			2,300	71
594	28		622	72
20,057	4,375		24,432	73
2,383,400			2,383,400	74
12,520	458		12,978	75
176,087	18,638	12,883	207,608	76
2,438,228	189,758	180,127	2,808,113	77
1,767,967			1,767,967	78
1,955,538	389,276	122,293	2,467,107	79
1,891			1,891	80
1,891			1,891	81
4,500			4,500	82
21,837	577		22,414	83
2,269	306		2,575	84
594,000	65,941		659,941	85
1,333,160		111,850	1,445,010	86
10,748	—	—	10,748	87

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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

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 Classifi-cation (d)
88	Public Service Co. of NM (AC)	Public Service Co. of NM	Public Service Co. of NM	NF
89	Public Service Co. of NM (AC)	Tucson Electric Power Co	El Paso Electric Co.	NF
90	Public Service Co. of NM (AC)	Salt River Project	Salt River Project	NF
91	Public Service Co. of NM (AC)	El Paso Electric Co.	Public Service Co. of NM	NF
92	Public Service Co. of NM (AC)	Public Service Co. of NM	El Paso Electric Co.	NF
93	Public Service Co. of NM (AC)	El Paso Electric Co.	Public Service Co. of NM	NF
94	Public Service Co. of NM (AC)	Public Service Co. of NM	Arizona Public Service Co	NF
95	Public Service Co. of NM (AC)	Public Service Co. of NM	El Paso Electric Co.	NF
96	Public Service Co. of NM-Whlse (Y)			
97	Pueblo of Acoma Utility Authority (AE,AG)	Pueblo of Acoma Utility Authority	Pueblo of Acoma Utility Authority	FNO
98	Rainbow Energy Marketing (AC)	El Paso Electric Co.	Southwestern Public Service Co.	NF
99	Rainbow Energy Marketing (AC,AF)	El Paso Electric Co.	Southwestern Public Service Co.	SFP
100	Rainbow Energy Marketing (AC,AF)	Public Service Co. of NM	El Paso Electric Co.	SFP
101	Red Cloud Wind LLC (AI,AJ)	Public Service Co. of NM	Arizona Public Service Co	LFP
102	Salt River Project (AT)	Salt River Project	Salt River Project	LFP
103	Salt River Project (AC)	Arizona Public Service Co	Tucson Electric Power Co	NF
104	Salt River Project (AC,AF)	Western Area Power Adminis	Arizona Public Service Co	SFP
105	Salt River Project (AC,AF)	Western Area Power Adminis	Public Service Co. of NM	SFP
106	Tecolote Wind LLC (AK,AL,AM)	Public Service Co. of NM	Arizona Public Service Co	LFP
107	Tecolote Wind LLC (AC)	Public Service Co. of NM	Arizona Public Service Co	NF
108	Tecolote Wind LLC (AC)	Public Service Co. of NM	Arizona Public Service Co	NF
109	Tecolote Wind LLC (AC)	Public Service Co. of NM	Public Service Co. of NM	NF
110	Tenaska Power Services Co. (AC)	El Paso Electric Co.	Tucson Electric Power Co	NF
111	Tenaska Power Services Co. (AC)	Southwestern Public Service Co.	El Paso Electric Co.	NF
112	Tenaska Power Services Co. (AC)	Tucson Electric Power Co	El Paso Electric Co.	NF
113	Tenaska Power Services Co. (AC,AF)	El Paso Electric Co.	El Paso Electric Co.	SFP
114	Tenaska Power Services Co. (AC,AF)	El Paso Electric Co.	El Paso Electric Co.	SFP
115	Tenaska Power Services Co. (AC,AF)	El Paso Electric Co.	Tucson Electric Power Co	SFP
116	Tenaska Power Services Co. (AC,AF)	Public Service Co. of NM	Tucson Electric Power Co	SFP
117	Tenaska Power Services Co. (AC,AF)	Tucson Electric Power Co	El Paso Electric Co.	SFP
118	Tenaska Power Services Co. (AC,AF)	Tucson Electric Power Co	Tucson Electric Power Co	SFP
119	The Energy Authority (AC)	El Paso Electric Co.	Southwestern Public Service Co.	NF
120	The Energy Authority (AC)	Southwestern Public Service Co.	El Paso Electric Co.	NF
121	The Energy Authority (AC,AF)	Arizona Public Service Co	Tucson Electric Power Co	SFP
122	Tri-State G&T Assn (W,AE)	Tri-State G&T Assn	Tri-State G&T Assn	FNO
123	Tri-State Generation and Transmission (AC)	Public Service Co. of NM	Public Service Co. of NM	NF
124	Tri-State Generation and Transmission (AC,AF)	El Paso Electric Co.	Tucson Electric Power Co	SFP
125	Tri-State Generation and Transmission (AC,AF)	Public Service Co. of NM	Public Service Co. of NM	SFP
126	Tri-State Generation and Transmission (AC,AF)	Public Service Co. of NM	Public Service Co. of NM	SFP
127	Tri-State Generation and Transmission (AC,AF)	Tri-State G&T Assn.	Public Service Co. of NM	SFP
128	Tucson Electric Power Company (AC)	El Paso Electric Co.	Arizona Public Service Co	NF
129	Tucson Electric Power Company (AC)	El Paso Electric Co.	Public Service Co. of NM	NF
130	Tucson Electric Power Company (AC)	Public Service Co. of NM	Arizona Public Service Co	NF
131	Tucson Electric Power Company (AC)	El Paso Electric Co.	Tucson Electric Power Co	NF
132	Tucson Electric Power Company (AC,AF)	El Paso Electric Co.	Public Service Co. of NM	SFP
133	Tucson Electric Power Company (AC,AF)	El Paso Electric Co.	Tucson Electric Power Co	SFP
134	Tucson Electric Power Company (AC,AF)	Tucson Electric Power Co	Tucson Electric Power Co	SFP
135	US Bureau of Reclamation (AD)	Arizona Public Service Co.	Western Area Power Admin.	OS
136	WAPA - Kirtland Air Force Base (T,AE)	Western Area Power	Kirtland Air Force Base	FNO

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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

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 MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
Tariff Vol. 6	Albuquerque	San Juan		1,720	1,720	88
Tariff Vol. 6	Greenlee	Luna		1,643	1,643	89
Tariff Vol. 6	Palo Verde	West Wing		510	510	90
Tariff Vol. 6	Hidalgo	San Juan		132	132	91
Tariff Vol. 6	San Juan	Mimbres		1,043	1,043	92
Tariff Vol. 6	Mimbres	Alamogordo		14	14	93
Tariff Vol. 6	Albuquerque	Four Corners		57	57	94
Tariff Vol. 6	San Juan	Luna		80	80	95
				—	—	96
Tariff Vol. 6	San Juan	Shiprock	—	—	—	97
Tariff Vol. 6	Amrad	Eddy	—	699	699	98
Tariff Vol. 6	Amrad	Eddy	—	—	—	99
Tariff Vol. 6	San Juan	West Mesa	—	670	670	100
Tariff Vol. 6	Western Spirit	Four Corners	331	77,208	77,208	101
Tariff Vol. 6	Palo Verde	Kyrene	184	11,561	11,561	102
Tariff Vol. 6	Four Corners	Coronado	—	1,712	1,712	103
Tariff Vol. 6	Shiprock	Four Corners	—	2,366	2,366	104
Tariff Vol. 6	Shiprock	San Juan	—	892	892	105
Tariff Vol. 6	Western Spirit	Four Corners	163	595,538	595,538	106
Tariff Vol. 6	San Juan	Four Corners	—	25	25	107
Tariff Vol. 6	Western Spirit	Four Corners	—	16,868	16,868	108
Tariff Vol. 6	Western Spirit	San Juan	—	61,004	61,004	109
Tariff Vol. 6	Luna	Greenlee	—	540	540	110
Tariff Vol. 6	Eddy	Amrad	—	26,040	26,040	111
Tariff Vol. 6	Greenlee	Hidalgo	—	174,873	174,873	112
Tariff Vol. 6	Hidalgo	Hidalgo	—	—	—	113
Tariff Vol. 6	Luna	Hidalgo	—	30	30	114
Tariff Vol. 6	Luna	Greenlee	—	7,640	7,640	115
Tariff Vol. 6	San Juan	Greenlee	—	12	12	116
Tariff Vol. 6	Greenlee	Hidalgo	—	650	650	117
Tariff Vol. 6	Springerville	Coronado	—	3	3	118
Tariff Vol. 6	Amrad	Eddy	—	—	—	119
Tariff Vol. 6	Eddy	Amrad	—	394	394	120
Tariff Vol. 6	Four Corners	Springerville	—	7	7	121
Tariff Vol. 6	San Juan	Shiprock	—	1,795,109	1,795,109	122
Tariff Vol. 6	San Juan	Ojo	—	—	—	123
Tariff Vol. 6	Hidalgo	Greenlee	—	46	46	124
Tariff Vol. 6	San Juan	Albuquerque	—	2,880	2,880	125
Tariff Vol. 6	San Juan	Ojo	—	318	318	126
Tariff Vol. 6	Ambrosia	San Juan	—	2,337	2,337	127
Tariff Vol. 6	West Mesa	Four Corners	—	296	296	128
Tariff Vol. 6	West Mesa	San Juan	—	5,616	5,616	129
Tariff Vol. 6	San Juan	Four Corners	—	—	—	130
Tariff Vol. 6	Luna	Greenlee	—	2,814	2,814	131
Tariff Vol. 6	West Mesa	San Juan	—	61,141	61,141	132
Tariff Vol. 6	Luna	Greenlee	—	563	563	133
Tariff Vol. 6	Springerville	Greenlee	—	—	—	134
85	Four Corners	Gallegos Sub	—	48,439	48,439	135
Tariff Vol. 6	San Juan	Shiprock	—	409,255	409,255	136

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
18,436	—	—	18,436	88
17,742	—	—	17,742	89
5,510	—	—	5,510	90
1,426	—	—	1,426	91
9,987			9,987	92
127			127	93
517			517	94
726			726	95
—	—	(65,220)	(65,220)	96
124,545	12,232	9,249	146,026	97
46,157	1,498		47,655	98
1,297	13		1,310	99
7,565	549		8,114	100
13,776,083	814,622		14,590,705	101
9,294,453	35,028		9,329,481	102
9,726			9,726	103
19,193			19,193	104
9			9	105
6,783,988	479,521		7,263,509	106
2,846			2,846	107
388,650			388,650	108
1,035,157			1,035,157	109
4,550			4,550	110
198,000	17,998		215,998	111
7,940	1,024		8,964	112
227			227	113
324	12		336	114
140,548	1,439		141,987	115
109			109	116
5,126			5,126	117
218			218	118
270			270	119
6,754	332		7,086	120
76			76	121
9,613,206	1,636,751	689,826	11,939,783	122
281			281	123
418			418	124
22,166	(81)		22,085	125
4,888	302		5,190	126
21,231	368		21,599	127
7,715			7,715	128
91,326	458		91,784	129
545			545	130
52,147			52,147	131
683,303	59,685		742,988	132
37,860	1,654		39,514	133
3,631			3,631	134
—		—	—	135
3,220,387	335,467	236,148	3,792,002	136

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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

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 Classifi-cation (d)
137	Western Area Power Administration (C)	Arizona Public Service Co.	El Paso Electric Co.	OLF
138	Western Area Power Administration (C)	Western Area Power Administration	City of Gallup Electric Utility	OLF
139	Western Area Power Administration (C)	Western Area Power Administration	Holloman Air Force Base	OLF
140	Western Area Power Administration (C)	Western Area Power Administration	Kirtland Air Force Base	OLF
141	Western Area Power Administration (C)	Western Area Power Administration	Los Alamos County Utilities/ DOE	OLF
142	Western Area Power Administration (C)	Western Area Power Administration	Southwestern Public Service Co	OLF
143	Western Area Power Administration (C)	Western Area Power Administration	Tri-State G & T Assn.	OLF
144	Western Spirit Contract Revenue (AR)			OS
145	Annual Formula Rate True Up (AH)			AD
146	Other (Z)			AD
147				
148				
149				
150	TOTAL			
151				
152				
153				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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

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 MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
87	Four Corners	West Mesa	198			137
86	Four Corners	Gallegos Sub	3	24,980	24,980	138
86	Four Corners	Holloman AFB	2	5,925	5,925	139
85	Four Corners	Kirtland AFB	3	36,434	36,434	140
86	Four Corners	DOE/Los Alamos	35	287,641	287,641	141
86	Four Corners	Blackwater	1	—	—	142
87	Four Corners	Albuquerque/West Mesa	35	654,087	654,087	143
						144
						145
						146
						147
						148
						149
			2,575	9,335,650	9,335,650	150
						151
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
3,238,440	1,253,646	—	4,492,086	137
—		—	—	138
—		—	—	139
—		—	—	140
—		—	—	141
—		—	—	142
—		—	—	143
		7,290,574	7,290,574	144
		(2,344,564)	(2,344,564)	145
		6	6	146
			—	147
			—	148
			—	149
134,762,860	8,544,025	6,362,581	149,669,466	150
			—	151
			—	152
			—	153
			—	154
			—	155
			—	156
			—	157
			—	158
			—	159
			—	160
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			—	174
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			—	179
			—	180
			—	181
			—	182
			—	183
			—	184
			—	185

FOOTNOTE DATA

Page 328, Row 1, Column (a)

(A) Transmission service for City of Farmington Electric Utility's from SJGS 345 kV bus and Shiprock Station side of the SJGS 230 kV breaker. Service continues as long as the transmission facilities remain in-service.

(B) Not used.

(C) Energy transmitted under Exchange Agreement with Western Area Power Administration (WAPA). Contract renewed in ten-year increments, currently in effect through May 2027.

(D) Aragonne Wind, LLC Long-Term PTP OATT agreements (50 MW, 40 MW, 40 MW, and 15 MW) for 145 MW effective January 4, 2022 through January 1, 2034. When MWH's are redirected to another path, they are shown as a separate line noted as long-term.

(E) Aragonne Wind, LLC Long-Term PTP OATT agreements (15MW and 25MW) for 40 MW effective January 1, 2017 through December 31, 2026. Aragonne Wind, LLC Long-Term PTP OATT agreement for 15 MW effective January 1, 2024 through December 31, 2033. When MWH's are redirected to another path, they are shown as a separate line noted as long-term.

(F) El Paso Electric Co. Long-Term PTP OATT revised agreement for 104 MW yearly firm sliding effective July 1, 2022 through July 1, 2027. When MWH's are redirected to another path, they are shown as a separate line noted as long-term.

(G) Not used.

(H) High Lonesome Mesa Wind Long-Term PTP OATT agreement for 90 MW effective June 1, 2009 through December 31, 2027.

(I) High Lonesome Mesa Wind Long-Term PTP OATT agreement for 10 MW effective May 1, 2009 through December 31, 2028.

(J) Arizona Electric Power Cooperative, Long-Term PTP OATT Fourth revised agreement for 40 MW effective January 1, 2023 through January 1, 2028.

(K) Broadview Energy JN, LLC Long-Term PTP OATT agreement for 125 MW effective May 1, 2017 through December 31, 2041.

(L) Broadview Energy JN, LLC Long-Term PTP OATT revised agreement for 42 MW Effective January 1, 2022 through December 31, 2041.

(M) Broadview Energy KW, LLC Long Term PTP OATT agreement for 130 MW effective January 1, 2022 through December 31, 2041.

(N) El Cabo Wind, LLC, Long Term PTP OATT agreement for 170 MW effective March 1, 2022 through March 1, 2027.

(O) El Cabo Wind, LLC, Long Term PTP OATT agreement for 38 MW effective June 1, 2022 through June 1, 2027.

(P) El Cabo Wind, LLC, Long Term PTP OATT agreement for 5 MW effective October 1, 2017 through September 31, 2044.

(Q) El Cabo Wind, LLC, Long term PTP OATT agreement for 56 MW effective June 1, 2022 through June 1, 2027.

(R) Network Integration Transmission Service provided to City of Gallup for service to the City of Gallup (COG) effective June 30, 2014. The service agreement shall remain in effect unless terminated by mutual agreement of the parties. Other charges represent Tier 1 redispatch charges.

(S) Network Integration Transmission Service provided by PNM for service to the Jicarilla Apache Nation. First Revised Service Agreement effective June 9, 2025. Other charges represent Tier 1 redispatch charges.

(T) Network Integration Transmission Service provided to WAPA – Kirtland Air Force Base, initiated January 1, 2009. The agreement shall remain in force and be subject to termination by mutual agreement of PNM and WAPA with one-year written notice. Other charges represent Tier 1 redispatch charges.

(U) Network integration Transmission Service provided to Los Alamos County (LAC), initiated August 1, 2002 shall remain in effect as long as the County requires transmission service for one or more of the Network Resources identified in Section 2.1 of the Fifth Revised Agreement for Network Integration Transmission Service unless terminated earlier by the mutual written agreement of the Parties. Other charges represent Tier 1 redispatch charges.

(V) Network Integration Transmission Service provided to Navajo Tribal Utility Authority (NTUA). The service agreement shall remain in effect unless terminated by mutual agreement of the Parties. Other charges represent Tier 1 redispatch charges.

(W) Network Integration Transmission Service provided to Tri-State Generation & Transmission Association (TSPM) terminates December 31, 2050 or by mutual agreement. Other charges represent Tier 1 redispatch charges.

(X) Network Integration Transmission Service provided to Kit Carson Electric Cooperative (KCEC). The service agreement shall remain in effect unless terminated by mutual agreement of the parties. Other charges represent Tier 1 redispatch charges.

(Y) PNM Financial Statement Adjustment for the elimination of PNM Wholesale Power Intercompany transactions for short term PTP transmission service.

(Z) Accounting adjustments.

(AA) Grady Wind Energy Center Long-Term PTP OATT agreement for 75 MW effective October 1, 2024 through October 1, 2044.

(AB) Grady Wind Energy Center Long-Term PTP OATT agreement for 125 MW effective March 1, 2024 through October 1, 2044.

(AC) Revenues relating to PNM's OATT FERC have been reported as follows for 2025: Column (k) Demand charges reflect rates which are based upon reserved rather than scheduled energy and include revenues associated with OATT Schedules 1,2,3,5,6,7, & 8; Column (l) Energy charges include revenues associated with OATT Schedules 4 and Real Power Losses, OATT 15.7.

(AD) U.S. Bureau of Reclamation-Gallegos Substation-full amortization of contribution in aid of construction ended June 1, 2010, and there will be no additional billing for the MWh.

(AE) Per FERC ruling PNM is allowed to bill Tier 1 fuel costs to the appropriate network customer, of which a portion is credited to the Fuel Clause.

(AF) Short-term firm tariff demand not specified in a firm transmission contract. Demand charges are calculated based on hourly, daily or monthly reserved transmission pursuant to Public Service Company of New Mexico's (PNM) Open Access Transmission Tariff (OATT) and vary for each transmission purchase.

(AG) Network Integration Transmission Service provided to the Pueblo of Acoma (Acoma). The service agreement shall remain in effect unless terminated by mutual agreement of the parties. Other charges represent Tier 1 redispatch charges.

(AH) Public Service Co. of New Mexico annual formula rate true up.

(AI) Red Cloud Wind LLC, Long Term PTP OATT agreement for 200 MW effective December 1, 2021 through December 1, 2059.

(AJ) Red Cloud Wind LLC, Long Term PTP OATT agreement for 131 MW effective December 1, 2021 through December 1, 2059.

(AK) Tecolote Wind LLC, Long Term PTP OATT agreement for 69 MW effective December 1, 2021 through December 1, 2059.

(AL) Tecolote Wind LLC, Long Term PTP OATT agreement for 81 MW effective December 1, 2021 through December 1, 2059.

(AM) Tecolote Wind LLC, Long Term PTP OATT agreement for 13 MW effective December 1, 2021 through December 1, 2059.

(AN) Clines Corners Wind Farm LLC, Long Term PTP OATT agreement for 119 MW effective December 1, 2021 through December 1, 2059.

(AO) Clines Corners Wind Farm LLC, Long Term PTP OATT agreement for 124 MW effective December 1, 2021 through December 1, 2059.

(AP) Duran Mesa LLC, Long Term PTP OATT agreement for 63 MW effective December 1, 2021 through December 1, 2059.

(AQ) Not used.

(AR) Contract revenue related to financing component of the Western Spirit agreements.

(AS) Leeward Renewable Energy Development, LLC Long-Term PTP OATT agreement for 35 MW effective January 4, 2022 through January 1, 2027.

(AT) Salt River Project, Long Term PTP OATT agreement for 184 MW effective January 1,2024 through January 1, 2029.

(AU) Guzman Energy LLC, Long Term PTP OATT agreement for 26 MW effective April 1, 2024 through April 1, 2029.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other
Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Megawatt-hours Received	Megawatt-hours Delivered	Demand Charges ($)	Energy Charges ($)	Other Charges ($)	Total Cost of Transmission ($)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	AZ Public Sv. Co. (A)	LFP	1,044	1,044	3,698,519	649	—	3,699,168
2	AZ Public Sv. Co. (B)	LFP	—	—	1,415,030	—	—	1,415,030
3	AZ Public Sv. Co. (C)	LFP	120	120	424,900	—	—	424,900
4	AZ Public Sv. Co. (M)	SFP	346,724	346,724	—	657,980	—	657,980
5	AZ Public Sv. Co. (M)	NF	—	—	1,256,589	—	—	1,256,589
6	El Paso Electric (D)	LFP	75,108	75,108	898,922	84,277	—	983,199
7	El Paso Electric (E)	LFP	144,698	144,698	1,974,190	(519,651)	—	1,454,539
8	El Paso Electric (F)	LFP	86,516	86,516	1,010,151	(404,938)	—	605,213
9	El Paso Electric (G)	LFP	98,826	98,826	377,722	60,338	—	438,060
10	El Paso Electric (H)	LFP	134,569	134,569	482,793	10,879	—	493,672
11	El Paso Electric (I)	LFP	259	259	1,428,817	(320,724)	—	1,108,093
12	El Paso Electric (M)	SFP	—	—	6,638,517	572,733	—	7,211,250
13	El Paso Electric (M)	NF	400,176	400,176	154,925	7,413	—	162,338
14	Salt River Project (M)	SFP	13,259	13,259	—	518,653	—	518,653
15	Salt River Project (M)	NF	—	—	20,016	—	—	20,016
16	SWTC, Inc. (M)	NF	71	71	198	—	—	198
17	Tri-State G & T (K,L)	LFP	36,000	36,000	640,452	—	—	640,452
18	Tucson Electric Power (J)	LFP	70,284	70,284	(58,079)	316,452	—	258,373
19	Tucson Electric Power (M)	SFP	185,722	185,722	1,691,997	440,898	—	2,132,895
20	Tucson Electric Power (M)	NF	4,598	4,598	189,888	17,852	—	207,740
21	WAPA - CRCM (M)	NF	4,982	4,982	100,714	7,586	—	108,300
22	WAPA - WALC (M)	SFP	—	—	2,671	776,347	—	779,018
23	WAPA - WALC (M)	NF	—	—	2	(5,032)	—	(5,030)
24	WAPA - WACM (M)	SFP	—	—	36,054	—	—	36,054
25	TOTAL		1,602,956	1,602,956	22,384,988	2,221,712	—	24,606,700

Page 332, Row 1, Column (a)

(A) Arizona Public Service Co. Two Transmission Service Agreements (22MW and 65 MW) revised for a total of 87MW WestWing to Four Corners effective January 1, 2023 through January 1, 2028.
(B) Arizona Public Service Co. Transmission Service Agreement for 130 MW Palo Verde to San Juan Entitlement which expires October 24, 2028.
(C) Arizona Public Service Co. Transmission Service Agreement for 10 MW Kyrene to Four Corners effective January 1, 2024 through January 1, 2029.
(D) El Paso Electric Co. Long Term Point to Point (PTP) OATT Service Agreement for 30 MW Afton to West Mesa effective January 1, 2024 and expires January 1, 2029.
(E) El Paso Electric Co. Long Term PTP OATT Service Agreement for 111 MW Afton to West Mesa effective January 1, 2024 through January 1, 2029. Credit is for the redirect of long term PTP to short term PTP on a different transmission path.
(F) El Paso Electric Co. Long Term PTP OATT Service Agreement for 94 MW Afton to Springerville effective August 1, 2019 through August 1, 2024. Renewed August 1, 2024 through August 1, 2029. Credit is for the redirect of long term PTP to short term PTP on a different transmission path.
(G) El Paso Electric Co. Long Term PTP OATT Service Agreement for 25 MW West Mesa to Amrad effective July 1, 2023 and expires July 1, 2028.
(H) El Paso Electric Co. Long Term PTP OATT Service Agreement for 60 MW Luna to Springerville for the period January 1, 2025 through January 1, 2030.
(I) El Paso Electric Co. Long term PTP OATT Service Agreement for 40 MW Las Cruces to Amrad effective May 1, 2022 through April 30, 2027. Credit is for the redirect of long term PTP to short term PTP on a different transmission path.
(J) Tucson Electric Power Co. Long Term PTP OATT Service Agreement for 14 MW San Juan to Greenlee effective January 1, 2024 through January 1, 2029.
(K) Tri-State Generation and Transmission Assn. Long term PTP OATT Service Agreement for 3 MW Las Cruces to Alamogordo effective May 1, 2022 through April 30, 2027.
(L) Tri-State Generation and Transmission Assn. Network Integration Service Agreement for Clayton /Van Buren which shall continue in force and effect until January 31, 2032 or earlier as mutually agreed with one year written advance notice by either.
(M) Short term firm and non-firm tariff demand not specified in a firm transmission pursuant to seller's filed transmission tariff and vary for each purchase by PNM.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	908,045
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	Arizona Public Service Palo Verde Expense	8,132,135
7	Arizona Public Service Four Corners Expense	3,179,320
8	Directors Fees & Expense	978,289
9	Commitment Fees	1,068,702
10	Writeoff Account Clean up	(99,127)
11	Non refundable Engineering Studies	(150,000)
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46	TOTAL	14,017,364

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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	10,722,803	362,017	—	—	11,084,820
3	Nuclear Production Plant	18,811,138	134,219	—	—	18,945,357
4	Hydraulic Production Plant-Conventional	—	—	—	—	—
5	Hydraulic Production Plant-Pumped Storage	—	—	—	—	—
5.1	Solar Production Plant	10,005,853	—	—		10,005,853
5.2	Wind Production Plant	—	—	—	—	—
5.3	Other Renewable Production Plant	—	—	—	—	—
6	Other Production Plant	19,139,300	122,262	—	—	19,261,562
7	Transmission Plant	63,219,858	—	—	—	63,219,858
8	Distribution Plant	74,784,369	276	—	—	74,784,645
9	Regional Transmission and Market Operation	—	—	—	—	—
9.1	Energy Storage Plant	1,005,981	—	—	—	1,005,981
10	General Plant	9,011,121	315	—	—	9,011,436
11	Common Plant-Electric	—	—	—	—	—
12	TOTAL	206,700,423	619,089	—	—	207,319,512

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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)
13	310	311					
14	310 Algondones	7					
15	310 Reeves	611					
16	310.1 Four Corners	15	100		2.81 %	SQ	
17	310.1 Reeves	11	100		0.41 %	SQ	
18	311 Algodones	645	75	(10.00)%		R2	
19	311 Four Corners	26,550	75	(10.00)%	1.58 %	R2	
20	311 Reeves	6,876	75	(10.00)%	5.00 %	R2	8.25
21	312 Algodones	1,659	55	(10.00)%		L0	
22	312 Four Corners	263,610	55	(10.00)%	1.34 %	L0	
23	312 Reeves	45,985	55	(10.00)%	6.83 %	L0	8.06
24	314 Algodones	1,545	50	(10.00)%		L0	
25	314 Four Corners	38,660	50	(10.00)%	2.21 %	L0	
26	314 Reeves	36,006	50	(10.00)%	5.30 %	L0	7.91
27	315 Algodones	196	60	(7.00)%		R0.5	
28	315 Four Corners	19,726	60	(7.00)%	1.26 %	R0.5	
29	315.2 Four Corners	889					
30	315.3 Four Corners	306			6.95 %		
31	315 Reeves	5,626	60	(7.00)%	9.28 %	R0.5	8.21
32	315.3 Reeves	17			6.67 %		
33	316 Algodones	39	53	(10.00)%		R0.5	
34	316 Four Corners	31,004	53	(10.00)%	2.07 %	R0.5	
35	316 Reeves	4,547	53	(10.00)%	9.46 %	R0.5	8.11
36	Subtotal Steam	484,841					
37	320 Palo Verde	440	75	(15.00)%		R2.5	
38	320.1 Palo Verde	45			1.50 %		26.50
39	321 Palo Verde - Common	60,583	75	(15.00)%	3.14 %	R2.5	24.78
40	321 Palo Verde - Unit 1	8,202	75	(15.00)%	2.89 %	R2.5	22.70
41	321 Palo Verde - Unit 2	11,496	75	(15.00)%	2.49 %	R2.5	23.49
42	321 Palo Verde - Unit 3	42,524	75	(15.00)%	1.83 %	R2.5	23.76
43	321 Palo Verde - Lease Buyout	81,719	75	(15.00)%	1.56 %	R2.5	23.54
44	322 Palo Verde - Common	20,537	75	(10.00)%	3.36 %	R1.5	24.24
45	322 Palo Verde - Unit 1	25,417	75	(10.00)%	3.26 %	R1.5	22.33
46	322 Palo Verde - Unit 2	57,487	75	(10.00)%	2.99 %	R1.5	23.16
47	322 Palo Verde - Unit 3	116,663	75	(10.00)%	2.47 %	R1.5	23.80
48	322 Palo Verde - Lease Buyout	112,883	75	(10.00)%	1.42 %	R1.5	23.05
49	323 Palo Verde - Common	806	75	(20.00)%	2.65 %	R0.5	23.32
50	323 Palo Verde - Unit 1	7,182	75	(20.00)%	3.48 %	R0.5	21.80
51	323 Palo Verde - Unit 2	16,493	75	(20.00)%	3.11 %	R0.5	22.61
52	323 Palo Verde - Unit 3	41,866	75	(20.00)%	2.88 %	R0.5	23.32
53	323 Palo Verde - Lease Buyout	46,003	75	(20.00)%	1.56 %	R0.5	22.56
54	324 Palo Verde - Common	2,106	60	(15.00)%	3.00 %	L2.5	23.19
55	324 Palo Verde - Unit 1	3,963	60	(15.00)%	2.42 %	L2.5	20.66
56	324 Palo Verde - Unit 2	4,842	60	(15.00)%	2.07 %	L2.5	21.46
57	324 Palo Verde - Unit 3	14,715	60	(15.00)%	2.27 %	L2.5	20.59
58	324.2 Palo Verde	10,006					
59	324.3 Palo Verde	408			6.95 %		
60	324 Palo Verde - Lease Buyout	30,603	60	(15.00)%	1.26 %	L2.5	22.42
61	325 Palo Verde - Common	37,436	50	(10.00)%	3.36 %	L1	21.92

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)
62	325 Palo Verde - Unit 1	1,581	50	(10.00)%	2.98 %	L1	19.58
63	325 Palo Verde - Unit 2	3,703	50	(10.00)%	2.33 %	L1	19.36
64	325 Palo Verde - Unit 3	5,759	50	(10.00)%	2.02 %	L1	19.35
65	325 Palo Verde - Lease Buyout	21,156	50	(10.00)%	1.46 %	L1	20.08
66	Subtotal Nuclear	786,624					
67	338.1	11,041					
68	338.2	268			3.40 %		
69	338.4	277,546			3.41 %		
70	338.5	8,265			4.15 %		
71	338.8	33,903			3.41 %		
72	338.9	52			20.00 %		
73	338.11	638			6.95 %		
74	338.12	5,228			3.42 %		
75	340.1 Afton	1,762	100		3.79 %	SQ	21.50
76	341 Afton	37,063	75	-10.00 %	3.17 %	R2	19.84
77	342 Afton	75,556	60	-10.00 %	3.37 %	S1	19.26
78	344 Afton	122,813	50	-10.00 %	3.85 %	R1.5	18.70
79	345 Afton	9,674	29	-10.00 %	5.05 %	S1.5	14.55
80	345.1 Afton	54			32.53 %		
81	345.3 Afton	39			6.95 %		
82	346 Afton	3,972	38	(10.00)%	3.34 %	S3	17.31
83	340 La Luz	820					
84	341 La Luz	22,388	75	(10.00)%	3.95 %	R2	21.92
85	342 La Luz	3,233	60	(10.00)%	4.00 %	S1	21.71
86	344 La Luz	20,277	50	(10.00)%	4.06 %	R1.5	20.98
87	345 La Luz	7,082	29	(10.00)%	5.17 %	S1.5	18.60
88	346 La Luz	627	38	(10.00)%	4.04 %	S3	21.74
89	341 Las Vegas	34	75	(10.00)%		R2	
90	342 Las Vegas	47	60	(10.00)%		S1	
91	340 Lordsburg	4,164					
92	340.1 Lordsburg	198	100		1.91 %	SQ	21.50
93	341 Lordsburg	9,557	75	(10.00)%	1.97 %	R2	19.67
94	342 Lordsburg	8,288	60	(10.00)%	3.65 %	S1	18.95
95	344 Lordsburg	35,476	50	(10.00)%	3.23 %	R1.5	18.50
96	345 Lordsburg	2,610	29	(10.00)%	4.37 %	S1.5	12.25
97	346 Lordsburg	4,121	38	(10.00)%	3.99 %	S3	16.83
98	340 Luna	1,504					
99	341 Luna	15,576	75	(10.00)%	2.66 %	R2	21.69
100	342 Luna	13,936	60	(10.00)%	2.90 %	S1	20.87
101	344 Luna	38,616	50	(10.00)%	3.08 %	R1.5	20.51
102	345 Luna	286	29	(10.00)%	5.10 %	S1.5	19.84
103	345.2 Luna	22					
104	346 Luna	36,197	38	(10.00)%	3.17 %	S3	19.83
105	340 Rio Bravo	754					
106	341 Rio Bravo	9,147	75	(10.00)%	3.01 %	R2	18.12
107	342 Rio Bravo	19,306	60	(10.00)%	3.02 %	S1	18.02
108	344 Rio Bravo	44,164	50	(10.00)%	3.28 %	R1.5	17.51
109	345 Rio Bravo	4,473	29	(10.00)%	4.62 %	S1.5	16.12
110	346 Rio Bravo	1,204	38	(10.00)%	3.49 %	S3	18.15

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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)
111	Subtotal Other Product	891,981					
112	350	80,896			2.63 %		
113	350.1	53,223	75		0.95 %	R2	57.75
114	351.1	18,462			32.53 %		
115	351.2	5,263					
116	351.3	46,596			6.95 %		
117	352	257,637	54	(5.00)%	2.63 %	S2.5	44.74
118	353	977,333	42	(20.00)%	2.79 %	R1	35.95
119	354	65,399	65	(10.00)%	2.79 %	R4	36.94
120	355	556,376	56	(75.00)%	3.37 %	R4	44.52
121	356	233,681	58	(60.00)%	2.63 %	R0.5	42.19
122	357	185	47	(5.00)%	1.90 %	R5	9.85
123	359	9,801	66		1.47 %	S6	51.77
124	Subtotal Transmission	2,304,852					
125	360	9,746			0.90 %		
126	360.1	2,121	75		0.90 %	R2	51.10
127	361	73,852	54	(5.00)%	1.73 %	S2.5	36.72
128	362	319,275	49	(25.00)%	2.52 %	R2	35.00
129	363.1	6,394			20.00 %		
130	363.2	40,016					
131	363.3	18,400			6.95 %		
132	364	440,032	47	(70.00)%	4.15 %	R2	31.96
133	365	290,183	46	(60.00)%	3.88 %	R2.5	29.43
134	366	192,030	57	(20.00)%	1.90 %	R4	36.03
135	367	463,649	50	(15.00)%	2.25 %	R2.5	33.92
136	368	285,896	49	(25.00)%	2.39 %	R2	33.08
137	369	101,795	54	(85.00)%	3.07 %	R1.5	41.38
138	369.1	174,620			2.98 %		39.81
139	370	66,513	31	(20.00)%	4.72 %	L2	
140	371	9,152	43	(35.00)%	1.98 %	R1	20.55
141	371.1	307	30		2.42 %	R5	5.20
142	373	30,275	35	(15.00)%	2.85 %	L0	24.65
143	Subtotal Distribution	2,524,256					
144	387.10	546			3.10 %		
145	387.2	668			3.10 %		
146	387.3	19,476			10.53 %		
147	387.5	4,827			4.15 %		
148	387.6	1,713			3.10 %		
149	387.9	424					
150	387.11	5,234			3.10 %		
151	Subtotal Energy Storage	32,888					
152	389	2,048					
153	390	74,238	47	(5.00)%	1.88 %	R2.5	31.64
154	390.1	5,904	25		0.19 %	SQ	12.78
155	390.2	5,966	47		2.13 %	R2.5	28.34
156	391	5,174	20		32.53 %	SQ	
157	391.3	296	5		20.00 %	SQ	
158	392	4,186	14	10.00 %	5.14 %	L4	8.07
159	392.1	5,036	13	8.00 %	4.85 %	L4	7.64

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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)
160	392.2	8,516	23	10.00 %	3.34 %	L2	15.64
161	393	98	15		6.67 %	SQ	
162	394	20,315	20		5.00 %	SQ	
163	395	206	10		10.30 %	SQ	
164	396	7,322	14	10.00 %	2.75 %	L2	6.42
165	397	789	15		6.95 %	SQ	
166	397.1	2,377			32.53 %		
167	397.2	9,886					
168	398	1,778	15		6.67 %	SQ	
169	Subtotal General	154,135					
170	Total	7,179,577					
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FOOTNOTE DATA

Page 337, Row 13, Column (c)

Column (b) represents actual depreciable balances as of December 31, 2025 and excludes intangibles and asset retirement costs. Average service life, depreciation rates, net salvage value, curve type, and remaining life (column (‘c) thru (g)) are based on a 2021 depreciation study. Annual depreciation rates as of January 3, 2024 were approved in NMPRC Case No. 22-00270-UT.

FOOTNOTE DATA

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	RATE CASE EXPENSES				
2			—	—	—
3			—	—	—
4			—	—	—
5			—	—	—
6			—	—	—
7	OTHER 928 AMOUNTS		—	—	—
8	Federal Regulatory Commission Annual Meeting		1,373,654	1,373,654	—
9	Energy Efficiency		38,611,593	38,611,593	—
10	Nuclear Regulatory Commission - Palo Verde		1,392,366	1,392,366	—
11	NMPRC Case Expense		26,093	26,093	—
12	Transporation Electrification		4,136,510	4,136,510	—
13	2024 rate change		966,274	966,274	—
14	2025 rate change		201,735	201,735	—
15	Solar Direct		33,225	33,225	—
16	Miscellaneous		807	807	
17					
18					
19					
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45					
	TOTAL	—	46,742,257	46,742,257	—

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

FOOTNOTE DATA

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 (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
			—		—	—	2
			—		—	—	3
		—	—		—	—	4
		—	—		—	—	5
		—	—		—	—	6
		—	—		—	—	7
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		—	—		—	—	9
		—	—		—	—	10
		—	—		—	—	11
		—	—		—	—	12
		—	—		—	—	13
		—	—		—	—	14
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		—	—		—	—	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

FOOTNOTE DATA

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	31,149,610		
4	Transmission	3,201,640		
5	Regional Market	—		
6	Distribution	12,946,718		
7	Customer Accounts	10,601,976		
8	Customer Service and Informational	1,144,307		
9	Sales	3,934,165		
10	Administrative and General	47,266,882		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	110,245,298		
12	Maintenance			
13	Production	12,725,361		
14	Transmission	2,885,462		
15	Regional Market	—		
16	Distribution	4,308,123		
17	Administrative and General	628,442		
18	TOTAL Maintenance (Total of lines 13 thru 17)	20,547,388		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	43,874,971		
21	Transmission (Enter Total of lines 4 and 14)	6,087,102		
22	Regional Market (Enter Total of Lines 5 and 15)	—		
23	Distribution (Enter Total of lines 6 and 16)	17,254,841		
24	Customer Accounts (Transcribe from line 7)	10,601,976		
25	Customer Service and Informational (Transcribe from line 8)	1,144,307		
26	Sales (Transcribe from line 9)	3,934,165		
27	Administrative and General (Enter Total of lines 10 and 17)	47,895,324		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	130,792,686	(10,945,024)	119,847,662
29	Gas			
30	Operation			
31	Production-Manufactured Gas	—		
32	Production-Nat. Gas (Including Expl. and Dev.)	—		
33	Other Gas Supply	—		
34	Storage, LNG Terminaling and Processing	—		
35	Transmission	—		
36	Distribution	—		
37	Customer Accounts	—		
38	Customer Service and Informational	—		
39	Sales	—		
40	Administrative and General	—		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	—		
42	Maintenance			
43	Production-Manufactured Gas	—		
44	Production-Natural Gas (Including Exploration and Development)	—		
45	Other Gas Supply	—		
46	Storage, LNG Terminaling and Processing	—		
47	Transmission	—		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

FOOTNOTE DATA

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	—		
49	Administrative and General	—		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	—		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	—		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,	—		
54	Other Gas Supply (Enter Total of lines 33 and 45)	—		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru 47)	—		
56	Transmission (Lines 35 and 47)	—		
57	Distribution (Lines 36 and 48)	—		
58	Customer Accounts (Line 37)	—		
59	Customer Service and Informational (Line 38)	—		
60	Sales (Line 39)	—		
61	Administrative and General (Lines 40 and 49)	—		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	—	—	—
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	130,792,686	(10,945,024)	119,847,662
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	18,460,315	33,705,675	52,165,990
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	18,460,315	33,705,675	52,165,990
72	Plant Removal (By Utility Departments)			
73	Electric Plant	3,097,860	3,808,166	6,906,026
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	3,097,860	3,808,166	6,906,026
77	Other Accounts (Specify, provide details in footnote):			
78	163 Stores Expense	1,039,388	(1,039,388)	—
79	182 Other Reg Assets	2,049,357	1,325,543	3,374,900
80	183 Prelim Survey & Invest	698,844	456,507	1,155,351
81	184 Clearing Accts	14,021,082	(14,021,082)	—
82	186 Deferred Debits	170,690	127,775	298,465
83	242 Accrued Liabilities	10,749,337	(10,854,468)	(105,131)
84	253 Deferred Credits	473,873	312,460	786,333
85	408 Payroll Taxes	(264,889)	(3,523,850)	(3,788,739)
86	416 Merch & Jobbing	202,107	239,120	441,227
87	426 Other Deductions	391,417	470,130	861,547
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	29,531,206	(26,507,253)	3,023,953
96	TOTAL SALARIES AND WAGES	181,882,067	61,564	181,943,631

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

FOOTNOTE DATA

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 Year (e)
1	Energy				
2	Net Purchases (Account 555)	1,362,040	2,469,342	3,117,497	3,666,024
3	Net Sales (Account 447)	(3,622,945)	(6,775,173)	(9,845,957)	(15,396,169)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	Energy Imbalance Market (Account 555)	11,951,917	22,802,609	43,993,658	62,289,320
8	Energy Imbalance Market (Account 447)	(6,506,848)	(17,737,411)	(40,378,030)	(58,198,375)
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46	Total	3,184,164	759,367	(3,112,832)	(7,639,200)

FOOTNOTE DATA

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	1,214,826	MWh's	367,542	6,982	MWh's	224,677
2	Reactive Supply and Voltage	1,214,826	MWh's	369,819	—		—
3	Regulation and Frequency Response				6,626	MWh's	2,170,762
4	Energy Imbalance				—		—
5	Operating Reserve - Spinning				2,147	MWh's	270,947
6	Operating Reserve - Supplement				2,147	MWh's	300,440
7	Other				—		—
8	Total (Lines 1 thru 7)	2,429,652		737,361	17,902		2,966,826

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

FOOTNOTE DATA

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 on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	4,585	20	19	1,614	434	2,255	208	74	50
2	February	4,254	19	8	1,322	364	2,255	211	102	20
3	March	4,412	19	7	1,347	354	2,255	213	243	187
4	Total for Quarter 1				4,283	1,152	6,765	632	419	257
5	April	4,195	26	19	1,289	267	2,255	184	200	—
6	May	4,544	23	17	1,480	335	2,255	185	289	95
7	June	5,123	16	17	2,085	464	2,255	181	138	107
8	Total for Quarter 2				4,854	1,066	6,765	550	627	202
9	July	5,178	10	17	2,123	475	2,255	191	134	79
10	August	5,157	5	18	2,083	514	2,255	190	115	44
11	September	4,643	8	18	1,835	364	2,255	184	5	44
12	Total for Quarter 3				6,041	1,353	6,765	565	254	167
13	October	4,304	2	17	1,498	286	2,255	215	50	44
14	November	4,217	26	19	1,382	312	2,255	211	57	181
15	December	4,323	4	21	1,495	362	2,255	211	—	1,063
16	Total for Quarter 4				4,375	960	6,765	637	107	1,288
17	Total Year to Date/Year	54,935			19,553	4,531	27,060	2,384	1,407	1,914

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FOOTNOTE DATA

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)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	1,801,361
4	Nuclear	2,291,795
5	Hydro-Conventional	—
6	Hydro-Pumped Storage	—
6.1	Solar	389,677
6.2	Wind	—
6.3	Other Renewable	—
7	Other	—
8	Less Energy for Pumping	—
9	Net Generation (Enter Total of lines 3 through 8)	4,482,833
10	Purchases	11,119,279
11	Power Exchanges:	
12	Received	160,476
13	Delivered	159,622
14	Net Exchanges (Line 12 minus line 13)	854
15	Transmission For Other (Wheeling)	
16	Received	9,335,650
17	Delivered	9,335,650
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)	15,602,966
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	10,045,453
23	Requirements Sales for Resale (See instruction 4, page 311.)	—
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,057,809
25	Energy Furnished Without Charge	—
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	18,827
27	Total Energy Losses	1,480,877
27.1	Total Energy Stored	—

FOOTNOTE DATA

28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	15,602,966

FOOTNOTE DATA

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 (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK: Megawatts (See Instr. 4) (d)	MONTHLY PEAK: Day of Month (e)	MONTHLY PEAK: Hour (f)
1	January	1,211,449	232,100	1,614	20	19
2	February	1,122,988	284,015	1,432	19	1
3	March	1,278,574	380,908	1,413	20	3
4	April	1,215,255	335,978	1,445	16	18
5	May	1,277,862	389,623	1,693	31	18
6	June	1,460,023	386,146	2,106	16	18
7	July	1,510,889	393,323	2,123	10	17
8	August	1,509,034	378,870	2,094	6	16
9	September	1,249,372	321,792	1,835	8	18
10	October	1,164,962	319,330	1,498	2	17
11	November	1,143,541	297,377	1,382	26	19
12	December	1,459,017	338,347	1,495	4	21
13	TOTAL	15,602,966	4,057,809			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

FOOTNOTE DATA

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Four Corners (1)* (b)			Plant Name: *Reeves* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor			Conventional Outdoor		
3	Year Originally Constructed	1969			1958		
4	Year Last Unit was Installed	1970			1962		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	200			146		
6	Net Peak Demand on Plant - MW (60 minutes)	197			143,297		
7	Plant Hours Connected to Load	6,681			6,060		
8	Net Continuous Plant Capability (Megawatts)	—			—		
9	When Not Limited by Condenser Water	—			—		
10	When Limited by Condenser Water	—			—		
11	Average Number of Employees	—			—		
12	Net Generation, Exclusive of Plant Use - KWh	391,426,000			166,540,800		
13	Cost of Plant: Land and Land Rights	15			619		
14	Structures and Improvements	26,550			6,876		
15	Equipment Costs	353,306			92,181		
16	Asset Retirement Costs	9,985			249		
17	Total Cost	389,856			99,925		
18	Cost per KW of Installed Capacity (line 17/5) Including	1.9493			0.6844		
19	Production Expenses: Oper, Supv, & Engr	659,333			1,109,524		
20	Fuel	38,234,550			7,148,018		
21	Coolants and Water (Nuclear Plants Only)	—			—		
22	Steam Expenses	6,454,200			0		
23	Steam From Other Sources	—			—		
24	Steam Transferred (Cr)	—			—		
25	Electric Expenses	131,479			1,041,086		
26	Misc Steam (or Nuclear) Power Expenses	1,445,216			235,073		
27	Rents	221,802			258,093		
28	Allowances	—			—		
29	Maintenance Supervision and Engineering	411,056			938,505		
30	Maintenance of Structures	2,244,833			2,038,691		
31	Maintenance of Boiler (or reactor) Plant	4,151,077			4,163,861		
32	Maintenance of Electric Plant	1,749,135			102		
33	Maintenance of Misc Steam (or Nuclear) Plant	977,109			0		
34	Total Production Expenses	56,679,790			16,932,953		
35	Expenses per Net KWh	0.1448			0.1017		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Gas		Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	T	Mcfe		Mcfe		
38	Quantity (Units) of Fuel Burned (from the Unit Type	227,574	87,855		5,291,564		
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9,021.000	947,220.000		1.028		
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	158.500	2.680		3.390		
41	Average Cost of Fuel per Unit Burned	158.500	2.680		3.518		
42	Average Cost of Fuel Burned per Million BTU	8.790	2.830		3.484		
43	Average Cost of Fuel Burned per KWh Net Gen	0.092	—		0.044		
44	Average BTU per KWh Net Generation	10,702.000	—		13,061.600		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

FOOTNOTE DATA

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Rio Bravo* (d)			Plant Name: *Palo Verde (1)* (e)			Plant Name: *Lordsburg Turbine* (e)			Line No.
Gas Turbine			Nuclear			Gas Turbine			1
Full Outdoor			Conventional			Full Outdoor			2
2000			1986			2001			3
2000			1988			2002			4
149			288			85			5
149			411			81			6
4,663			8,760			3,474			7
—			—			—			8
—			—			—			9
—			—			—			10
—			—			—			11
287,613,000			2,291,794,910			68,543,000			12
754			484			4,361			13
9,147			204,523			9,557			14
69,147			571,610			50,495			15
0			12,832			3,419			16
79,048			789,449			67,832			17
0.5305			2.7411			0.7980			18
77,995			6,680,617			5,127			19
9,137,607			16,670,741			2,547,986			20
—			5,538,377			0			21
—			2,535,713			0			22
—			—			—			23
—			—			—			24
0			3,676,362			0			25
0			10,763,521			0			26
—			108,240			0			27
—			—			—			28
0			1,108,190			0			29
796,219			714,064			0			30
0			3,140,308			0			31
1,114,593			4,916,246			1,608,564			32
—			861,121			0			33
11,126,414			56,713,500			4,161,677			34
0.0387			0.0247			0.0607			35
Gas/Oil			Nuclear			Gas			36
Mcfe			g			Mcfe			37
6,243,608			354			1,166,318			38
1.028			66,704.000			1.029			39
3.864			1,542.010			4.306			40
4.084			47,135.810			4.400			41
3.972			0.706			4.429			42
0.046			0.007			0.045			43
11,552.500			10,307.000			10,410.900			44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

FOOTNOTE DATA

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Afton Turbine* (b)			Plant Name: *Luna* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Full Outdoor			Full Outdoor		
3	Year Originally Constructed	2001			2006		
4	Year Last Unit was Installed	2002			2006		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	235			190		
6	Net Peak Demand on Plant - MW (60 minutes)	230			193		
7	Plant Hours Connected to Load	7,647			7,936		
8	Net Continuous Plant Capability (Megawatts)	—			—		
9	When Not Limited by Condenser Water	—			—		
10	When Limited by Condenser Water	—			—		
11	Average Number of Employees	—			—		
12	Net Generation, Exclusive of Plant Use - KWh	453,439,000			418,884,000		
13	Cost of Plant: Land and Land Rights	1,762			1,504		
14	Structures and Improvements	37,063			15,576		
15	Equipment Costs	212,108			89,036		
16	Asset Retirement Costs	754			1,054		
17	Total Cost	251,687			107,170		
18	Cost per KW of Installed Capacity (line 17/5) Including	1.0710			0.5641		
19	Production Expenses: Oper, Supv, & Engr	659,529			4,351,994		
20	Fuel	11,732,555			8,317,391		
21	Coolants and Water (Nuclear Plants Only)	—			—		
22	Steam Expenses	—			—		
23	Steam From Other Sources	—			—		
24	Steam Transferred (Cr)	—			—		
25	Electric Expenses	—			—		
26	Misc Steam (or Nuclear) Power Expenses	—			0		
27	Rents	—			—		
28	Allowances	—			—		
29	Maintenance Supervision and Engineering	—			—		
30	Maintenance of Structures	—			—		
31	Maintenance of Boiler (or reactor) Plant	—			—		
32	Maintenance of Electric Plant	7,102,591			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	—			0		
34	Total Production Expenses	19,494,675			12,669,385		
35	Expenses per Net KWh	0.0430			0.0302		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcfe			Mcfe		
38	Quantity (Units) of Fuel Burned (from the Unit Type	10,635,048			7,034,783		
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0.9432			0.9439		
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.237			4.299		
41	Average Cost of Fuel per Unit Burned	3.316			4.500		
42	Average Cost of Fuel Burned per Million BTU	3.053			4.057		
43	Average Cost of Fuel Burned per KWh Net Gen	0.025			0.032		
44	Average BTU per KWh Net Generation	7,762.100			7,515.200		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

FOOTNOTE DATA

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *La Luz* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Gas			1
Full Outdoor			2
2015			3
2015			4
41		—	5
40		—	6
2,066		—	7
—		—	8
—		—	9
—		—	10
—		—	11
14,915,000		—	12
658		—	13
22,388		—	14
31,219		—	15
1,781		—	16
56,046		—	17
1.3670		—	18
45,564		—	19
872,147		—	20
—		—	21
—		—	22
—		—	23
—		—	24
—		—	25
—		—	26
—		—	27
—		—	28
—		—	29
382,101		—	30
—		—	31
40,382		—	32
—		—	33
1,340,194		—	34
0.0899		—	35

									Line No.
Gas									36
Mcfe									37
742,352									38
1.027									39
4.924									40
5.024									41
5.058									42
0.055									43
11,181.400									44

Page 402, Row 1, Column (b)

PNM

PNM's capacity in commercial operation as of December 31, 2025, are as follows:

Type	Name	Location	Generation Capacity (MW)	Percent of Generation Capacity
Solar	PNM-owned solar	Twenty sites in New Mexico	158	3.3 %
Solar	Britton	Torrance County, New Mexico	50	1.1
Solar	Encino	Mexico	50	1.1
Solar	Encino North	Mexico	50	1.1
Solar	Solar Direct	Mexico	50	1.1
Solar	Route 66	Cibola County, New Mexico	50	1.1
Solar	Arroyo	McKinley County, New Mexico	300	6.3
Solar	Sky Ranch	Valencia County, New Mexico	190	4.0
Solar	Jicarilla I	Mexico	50	1.1
Solar	Atrisco	Bernalillo County, New Mexico	300	6.3
Solar	San Juan	Mexico	200	4.2
Solar	TAG	Mexico	140	3.0
Solar	Quail Ranch	Bernalillo County, New Mexico	100	2.1
Solar	Community Solar	Multiple sites in New Mexico	25	0.5
Solar	Other	Los Lunas, New Mexico	30	0.6
Wind	New Mexico Wind	House, New Mexico	200	4.2
Wind	Red Mesa Wind	Seboyeta, New Mexico	102	2.2
Wind	Casa Mesa Wind	House, New Mexico	50	1.1
Wind	La Joya Wind I	Torrance, New Mexico	166	3.5
Wind	La Joya Wind II	Torrance, New Mexico	140	3.0
Geothermal	Geothermal	Lordsburg, New Mexico	11	0.2
Renewable resources			2,412	51.0
Energy storage	PNM-owned battery	Valencia County & Bernalillo County, New Mexico	12	0.3
storage	Arroyo	McKinley County, New Mexico	150	3.2
storage	Jicarilla	Mexico	20	0.4
storage	Sky Ranch	Valencia County, New Mexico	50	1.1
storage	Sky Ranch II	Valencia County, New Mexico	100	2.1
storage	San Juan	Mexico	100	2.1
storage	Atrisco	Bernalillo County, New Mexico	300	6.3
storage	TAG	Mexico	50	1.1
storage	Route 66	Cibola County, New Mexico	50	1.1
Energy storage resources			832	17.6
Gas	Reeves Station	Albuquerque, New Mexico	146	3.1
Gas	Afton (combined cycle)	La Mesa, New Mexico	235	5.0
Gas	Lordsburg	Lordsburg, New Mexico	85	1.8
Gas	Luna (combined cycle)	Deming, New Mexico	190	4.0
Gas/Oil	Rio Bravo	Albuquerque, New Mexico	149	3.1
Gas	Valencia	Belen, New Mexico	155	3.3
Gas	La Luz	Belen, New Mexico	41	0.9
Gas-fired resources			1,001	21.1
Nuclear	PVNGS	Wintersburg, Arizona	288	6.1
Coal	Four Corners	Fruitland, New Mexico	200	4.2
			4,733	100.0 %

Renewable and Energy Storage Resources

In addition to PNM's owned and contracted solar facilities, PNM has a customer distributed solar generation program that represented 334.1 MW at December 31, 2025. PNM stores energy under ESAs and purchases renewable power under long-term PPAs, all currently having expiration dates beginning in January 2035 and extending through May 2047. The NMPRC has approved plans for PNM to procure energy and RECs from additional resources to serve retail customers and a data center located in PNM's service territory, some of which are expected to be in service by summer of 2026 and others that will be available for the 2028 summer peak. These approved resources are necessary for PNM to meet forecasted peak load requirements to serve its customers and to continue progress towards a carbon-free generating portfolio. If adjusted for these approved plans, the table above would reflect the percentage of generation capacity from renewable resources of 49.8%, energy storage resources of 26.0%, nuclear resources of 4.7%, and fossil-fueled resources of 19.6%. These resources and their currently expected operation dates are as follows:

Type	Application	Expected Operation	n Capacity (MW)
NMPRC approved			
Energy storage	2026 Resource Application	2026	100
PNM-owned battery	2026 Resource Application	2026	60
Gas	2028 Resource Application	2028	12
PNM-owned solar	2028 Resource Application	2028	100
PNM-owned battery	2028 Resource Application	2028	50
Energy storage	2028 Resource Application	2028	150
Energy storage	2028 Resource Application	2028	150
Solar	Meta Resources	2026	100
Solar	Meta Resources	2026	90
Solar	Meta Resources	2027	100
Energy storage	Meta Resources	2026	100
Energy storage	Meta Resources	2026	68
Energy storage	Meta Resources	2027	100
			1,180
NMPRC approval pending			
Energy storage	PNM-owned BESS Project	2027	30

Fossil-Fueled Plants

Four Corners Units 4 and 5 are 13% owned by PNM. These units are jointly owned with APS, SRP, Tucson, and NTEC, and are operated by APS. PNM had no ownership interest in Four Corners Units 1, 2, or 3, which were shut down by APS in 2013. The Four Corners plant site is located on land within the Navajo Nation and is subject to an easement from the federal government. APS, on behalf of the Four Corners participants, negotiated amendments to extend the owners' right to operate the plant on the site to July 2041.

PNM owns 100% of Reeves, Afton, Rio Bravo, Lordsburg, and La Luz and one-third of Luna. The remaining interests in Luna are owned equally by Tucson and Samchully Power & Utilities 1, LLC. PNM is also entitled to the entire output of Valencia under a PPA. Reeves, Lordsburg, Rio Bravo, La Luz, and Valencia are used primarily for peaking power and transmission support. As discussed in Note 10, Valencia is a variable interest entity and is consolidated by PNM.

Nuclear Plant

PNM is participating in the three units of PVNGS with APS (the operating agent), SRP, EPE, SCE, SCPPA, and the Department of Water and Power of the City of Los Angeles. PNM has ownership interests of 2.3% in Unit 1, 9.4% in Unit 2, and 10.2% in Unit 3. See Note 16 for information on other PVNGS matters.

Purchased Power

PNM engages in activities to optimize its existing jurisdictional assets and long-term power agreements through transacting in the hour-ahead, day-ahead, week-ahead, and month-ahead bilateral markets that allows PNM to market any excess generation not required to fulfill retail load and contractual commitments.

PNM participates in the EIM, a real-time wholesale energy trading market operated by CAISO, which enables participating electric utilities to buy and sell energy. Participation in the EIM has generated cost savings that are passed through to customers under PNM's FPPAC. PNM also plans to join the EDAM, which is a voluntary day-ahead regional market that expands on CAISO's EIM market, as early as 2027. PNM joined the WRAP in April 2023 to promote region-wide coordination between power providers for assessing and addressing resource adequacy. On October 28, 2025, PNM notified the Western Power Pool that it has elected to withdraw from WRAP and will not proceed into the binding phase. PNM will seek to align resource adequacy coordination with others in the EDAM regional market to maximize customer benefits.

Plant Operating Statistics

Equivalent availability of PNM's major base-load generating stations was:

Plant	Operator	2025	2024
Four Corners	APS	75.2%	78.1%
PVNGS	APS	92.3	91.8

Joint Projects

SJGS, PVNGS, Four Corners, and Luna are joint projects each owned or leased by several different entities. Some participants in the joint projects are investor-owned entities, while others are privately, municipally, tribally, or co-operatively owned. Furthermore, participants in SJGS had varying percentage interest in different generating units within the project and have different percentage interest with respect to plant decommissioning and coal mine reclamation obligations.

The primary operating or participation agreements for the other joint projects expire July 2041 for Four Corners, December 2046 for Luna, and November 2047 for PVNGS. As described above, Four Corners is located on land within the Navajo Nation and is subject to an easement from the federal government.

It is possible that other participants in the joint projects have circumstances and objectives that have changed from those existing at the time of becoming participants. The status of these joint projects is further complicated by the uncertainty surrounding the form of potential legislation and/or regulation of GHG, other air emissions, and CCRs, as well as the impacts of the costs of compliance and operational viability of all or certain units within the joint projects. It is unclear how these factors will enter into discussions and negotiations concerning the status of the joint projects as the expiration of basic operational agreements approaches. PNM can provide no assurance that its participation in the joint projects will continue in the manner that currently exists.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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	Albuquerque Solar	2011	2.00	2.0	4,106	9,169,711
2	Los Lunas Solar	2011	7.00	7.0	15,177	25,099,877
3	Deming Solar	2011	9.00	8.9	19,725	27,077,558
4	Alamogordo Solar	2011	5.00	4.9	10,678	19,676,362
5	Las Vegas Solar	2011	5.00	4.9	8,944	20,292,519
6	Manzano Solar	2013	8.40	8.2	18,125	18,740,924
7	Otero Solar	2013	8.00	7.8	17,596	17,483,453
8	Cibola Solar	2014	8.00	7.9	19,493	15,107,499
9	Meadowlake Solar	2014	8.90	8.8	22,870	18,232,661
10	Sandoval Solar	2014	6.10	6.3	15,656	13,333,895
11	Santa Fe Solar	2015	9.50	9.2	24,101	19,914,054
12	Santolina Solar	2015	10.50	10.0	26,807	20,459,354
13	South Valley Solar	2015	10.00	10.1	26,749	20,544,569
14	Rio Communities Solar	2015	10.00	10.1	23,169	20,452,017
15	Rio Del Oro Solar	2019	10.00	10.0	28,176	14,461,277
16	Rio Rancho Solar	2019	10.00	10.0	27,382	14,434,231
17	San Miguel 1 Solar	2019	10.00	10.0	26,259	13,912,986
18	San Miguel 2 Solar	2019	10.00	9.9	26,543	14,127,145
19	Vista Solar	2019	10.00	10.0	27,569	14,420,174
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

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	Operation Exc'l. Fuel	Production Expenses		Kind of Fuel	Fuel Costs (in cents (per Million Btu)	Generation Type	Line No.
		Fuel	Maintenance				
(g)	(h)	(i)	(j)	(k)	(l)	(m)	
4,584,856	23,687	—	24,236	Solar	—		1
3,585,697	82,905	—	84,826	Solar	—		2
3,008,618	106,592	—	109,062	Solar	—		3
3,935,272	59,218	—	60,590	Solar	—		4
4,058,504	59,218	—	60,590	Solar	—		5
2,231,062	94,749	—	96,944	Solar	—		6
2,185,432	88,827	—	90,885	Solar	—		7
1,888,437	94,749	—	96,944	Solar	—		8
2,048,614	106,592	—	109,062	Solar	—		9
2,185,884	71,062	—	72,708	Solar	—		10
2,096,216	112,514	—	115,121	Solar	—		11
1,948,510	124,358	—	127,239	Solar	—		12
2,054,457	118,436	—	121,180	Solar	—		13
2,045,202	118,436	—	121,180	Solar	—		14
1,446,128	118,436	—	121,180	Solar	—		15
1,443,423	118,436	—	121,180	Solar	—		16
1,412,715	118,436	—	121,180	Solar	—		17
1,391,299	118,436	—	121,180	Solar	—		18
1,442,017	118,436	—	121,180	Solar	—		19
							20
							21
							22
							23
							24
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FOOTNOTE DATA

Page 410, Row 1, Column (a)

For 2025, Prosperity Energy Storage Smart Grid is reported on Page 401a, line 27.1 as disclosure for Pages 419-420 ENERGY STORAGE OPERATIONS (Small Plants)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	End of 2025/Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 KW.
2. In columns (a), (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)
1	Rio Del Oro Solar Battery Storage		Valencia County, New Mexico	13,619,238
2	South Valley Solar Battery Storage		Bernalillo County, New Mexico	13,069,079
3	Prosperity Storage		Bernalillo County, New Mexico	6,379,343
4				
5				
6				
7				
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9				
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11				
12				
13				
14				
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16				
17				
18				
19				
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22				
23				
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35				
36	TOTAL			33,067,660.00

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

ENERGY STORAGE OPERATIONS (Small Plants) (Continued)

4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations Account No. 555.1 (g)	Power Purchased for Storage Operations (h)	Other Expenses (i)	Line No.
—	33,505	—	—	84,252	1
—	36,296	—	—	83,012	2
—	0	—	—	11,171	3
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					35
$ —	$ 69,801	$ —	$ —	$ 178,435	36

FOOTNOTE DATA

Page 420, Row 36, Column (i)

	December 31, 2025
Taxes other than income taxes	$ 153,519
Property insurance	24,916
TOTAL	$ 178,435

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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)
1	West Mesa	Window Rock	115.00	115.00	H Frame WD	109.10		1
2	Reeves	Los Alamos	115.00	115.00	H Frame WD	62.30		1
3	Alb 115KV Sys		115.00	115.00	H Frame WD	168.74		1
4	Mimbres Station	Las Cruces	115.00	115.00	H Frame WD	58.93		1
5	Mimbres Station	Hermanas	115.00	115.00	H Frame WD	2.93		1
6	Mimbres Station	Hurley Tap	115.00	115.00	H Frame WD	36.73		1
7	Person	El Cerro	115.00	115.00	H Frame WD			
8	Hermanas	Hondale	115.00	115.00	Single WD PL	8.50		1
9	Southern NM 115KV		115.00	115.00	HF-W,SP-W	118.33		
10	Alamogordo	Holloman	115.00	115.00	H Frame WD	2.50		
11	Las Vegas 115KV		115.00	115.00	H Frame WD	47.20		1
12	Santa Fe 115KV		115.00	115.00	H Frame WD	82.38		1
13	Person	Belen	115.00	115.00	H Frame WD	26.90		1
14	West Mesa	Ambrosia Lake	230.00	230.00	K Frame WD	68.72		1
15	Ambrosia Lake	Four Corners	230.00	230.00	K Frame WD	111.17		1
16	Kyrene Switchyard (9)		230.00	230.00	Steel	0.45		1
17	West Mesa	4 Corners #1	345.00	345.00	K Frame WD	154.77		1
18	West Mesa	San Juan	345.00	345.00	K Frame WD	208.20		1
19	4 Corners	San Juan (3)	345.00	345.00	K Frame WD	10.40		1
20	San Juan	Ojo SW Station	345.00	345.00	K Frame WD	154.21		1
21	San Juan	Vail (2)	345.00	345.00	Steel Towers	412.00		1
22	Sandia	West Mesa	345.00	345.00	K Frame WD	23.98		1
23	San Juan	McKinley (7)	345.00	345.00	Steel Delta	96.00		1
24	Hidalgo	Luna (5)	345.00	345.00	K Frame WD	50.20		1
25	McKinley	Springerville(7)	345.00	345.00	Steel Delta	96.00		1
26	Springerville	Coronado(7)	345.00	345.00	Lattice Steel	21.84		1
27	EIP BA	Blackwater	345.00	345.00	Lat tSteel	349.78		1
28	Norton	BA	345.00	345.00	K Frame WD	42.30		1
29	Palo Verde	West Wing I (6)	500.00	500.00	Steel Tower	46.08		1
30	Palo Verde	Kyrene (6)	500.00	525.00	Lattice Steel	73.00		1
31	Palo Verde	West Wing II (6)	500.00	500.00	Steel Tower	46.08		1
32	Panorama Station	Plains Electric	115.00	115.00	Steel	4.36		1
33	N. Bern Tap		115.00	115.00	Steel	0.09		1
34	BA Switch Station	Rio Rancho Tap	115.00	115.00	Steel	16.21		1
35	Pachmann	Progress	115.00	115.00	Steel	6.80		1

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	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 (n)	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
477 kcmil ACSR	13,294,194	41,893,792	55,187,986	—	—	—	—	1
477 kcmil ACSR	270,712	5,180,198	5,450,910	—	—	—	—	2
595.6 kcmil	793,051	22,725,958	23,519,009	—	—	—	—	3
477 kcmil ACSR	230,048	3,126,228	3,356,276	—	—	—	—	4
477 kc mil ACSR	24,875	593,506	618,381	—	—	—	—	5
477 kcmil ACSR	1,013	4,054,756	4,055,769	—	—	—	—	6
	912,283	3,716,131	4,628,414	—	—	—	—	7
477 kcmil ACSR	147,675	1,517,337	1,665,012	—	—	—	—	8
	4,705,472	23,674,282	28,379,754	—	—	—	—	9
	1,834	2,804,777	2,806,611	—	—	—	—	10
336.4 kcmil	120,380	2,363,076	2,483,456	—	—	—	—	11
477 kcmil ACSR	2,568,270	26,662,158	29,230,428	—	—	—	—	12
477 kcmil ACSR	128,868	5,145,897	5,274,765	—	—	—	—	13
954 kcmil ACSR	127,854	12,857,648	12,985,502	—	—	—	—	14
954 kcmil ACSR	150,910	6,379,183	6,530,093	—	—	—	—	15
2x2156 kcmil AC	—	3,525,694	3,525,694	—	—	—	—	16
2x795 kcmil	2,277,462	72,132,404	74,409,866	—	—	—	—	17
2x795 kcmil	1,788,385	43,652,351	45,440,736	—	—	—	—	18
2x795 kcmil	63,050	1,363,436	1,426,486	—	—	—	—	19
2x795 kcmil	1,427,669	25,884,726	27,312,395	—	—	—	—	20
2x954 kcmil	377,896	8,521,945	8,899,841	—	—	—	—	21
795 kcmil ACSR	939,239	11,718,813	12,658,052	—	—	—	—	22
2x954 kcmil	1,283	3,241,007	3,242,290	—	—	—	—	23
795 kcmil ACSR	192,350	1,702,764	1,895,114	—	—	—	—	24
2x954 kcmil	76,962	5,059,990	5,136,952	—	—	—	—	25
2x954 kcmil	108,037	3,755,399	3,863,436	—	—	—	—	26
795 kcmil ACSR	3,622,211	51,266,429	54,888,640	—	—	—	—	27
2x795 kcmil	917,318	12,014,104	12,931,422	—	—	—	—	28
3x1780 kcmil	—	1,318,692	1,318,692	—	—	—	—	29
3x1780 kcmil AC	—	3,436,452	3,436,452	—	—	—	—	30
3x1780 kcmil	296,209	1,656,802	1,953,011	—	—	—	—	31
477kcmil ACSR	7,024	1,953,037	1,960,061	—	—	—	—	32
795 kcmil ACSR	200	14,426	14,626	—	—	—	—	33
954 kcmil ACSR	5,744,030	6,606,055	12,350,085	—	—	—	—	34
795 kcmil ACSR	10,879	7,373,903	7,384,782	—	—	—	—	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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 (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
36	Rio Puerco	Veranda	115.00	115.00	Steel	12.00		1
37	Rio Puerco	Progress	115.00	115.00	Steel	12.12		
38	Belen 115KV		115.00	115.00	H Frame	4.00		1
39	Albuquerque	Grants (10)	115.00	115.00	H Frame	64.42		1
40	Grants	Bluewater (10)	115.00	115.00	H Frame	11.57		1
41	Bluewater	Ambrosia (10)	115.00	115.00	H Frame	14.18		1
42	Albuquerque	Algodones (10)	115.00	115.00	H Frame	8.80		1
43	Algodones	Espanola (10)	115.00	115.00	H Frame	75.99		1
44	Algodones	Moriarty (10)	115.00	115.00	H Frame	38.40		1
45	Moriarty	Willard (10)	115.00	115.00	Steel Sngl	29.27		1
46	OJO	Espanola	115.00	115.00	H Frame	4.10		1
47	Albuquerque	Belen	115.00	115.00	H Frame	35.90		1
48	Belen	Willard	115.00	115.00	H Frame	123.40		1
49	Ambrosia	Yah-Ta-Hey	115.00	115.00	H Frame			1
50	Hollywood	Gavilan	115.00	115.00	H Frame	1.70		1
51	North	Mission	115.00	115.00	H Frame	1.50		1
52	Greenlee	Hidalgo (4)	345.00	345.00	K Frame	59.90		1
53	BA	Norton	345.00	345.00	K Frame	22.30		1
54	BA	Diamond Tail	345.00	345.00	K Frame	49.90		1
55	Clines Corner	Western Spirit (11)	345.00	345.00	H Frame	34.40		1
56	Pajarito	Western Spirit (11)	345.00	345.00	H Frame	111.90		1
57	Prospertiy	Kirtland	115.00	115.00	Steel	0.70		1
58	Los Morros	St. Cecilia	115.00	115.00	Steel	2.34		1
59	Prosperity	Person	115.00	115.00	Steel	0.30		1
60	Sagebrush	Person	115.00	115.00	Steel	—		1
61	Prosperity	Studio	115.00	115.00	Steel	0.44		1
62	Sun Ranch	Rattesnake	115.00	115.00	Steel	4.40		1
63	Sagebrush	Sandia	115.00	115.00	Steel	0.42		1
64	Sun Ranvch	St. Cecilia	115.00	115.00	Steel	2.52		1
65	Rio Puerco	Quail Ranch	345.00	345.00	Steel	0.16		1
66	Quail Ranch	West Mesa	345.00	345.00	Steel	0.17		1
67	Hidden Mountain	Rattlesnake	115.00	115.00	Steel	4.80		1
68	Pillar	Four Corners	230.00	230.00	Steel	1.12		1
69	See 422-423.1 Footnote							
70					TOTAL	3,450.30	—	64

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	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 (n)	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
795 kcmil ACSR	2,790,678	4,185,088	6,975,766	—	—	—	—	36
795 kcmil ACSR	—	8,371,437	8,371,437	—	—	—	—	37
	(11,312)	2,078,874	2,067,562	—	—	—	—	38
266.8 kcmil ACSR	114,395	1,358,678	1,473,073	—	—	—	—	39
266.8 kcmil ACSR	13,618	11,663,720	11,677,338	—	—	—	—	40
266.8 kcmil ACSR	22,490	1,986,655	2,009,145	—	—	—	—	41
397.5 kcmil ACSR	1,781,243	4,309,396	6,090,639	—	—	—	—	42
397.5 kcmil ACSR			—	—	—	—	—	43
397.5 kcmil ACSR	140,260	2,394,592	2,534,852	—	—	—	—	44
397.5 kcmil ACSR	910,535	2,539,383	3,449,918	—	—	—	—	45
397.5 kcmil ACSR	43,097	533,967	577,064	—	—	—	—	46
397.5 kcmil ACSR	4,804,162	3,399,410	8,203,572	—	—	—	—	47
410 kcmil ACSR	2,594,253	15,642,994	18,237,247	—	—	—	—	48
397.5 kcmil ACSR	100,372	4,493,546	4,593,918	—	—	—	—	49
397.5 kcmil ACSR	—	521,437	521,437	—	—	—	—	50
397.5 kcmil ACSR	—	645,984	645,984	—	—	—	—	51
1272 pheasant	—	2,083,481	2,083,481	—	—	—	—	52
1272 pheasant	—	11,361,186	11,361,186	—	—	—	—	53
1272 pheasant	—	52,096,719	52,096,719	—	—	—	—	54
1272 pheasant	9,602,403	49,004,642	58,607,045	—	—	—	—	55
1272 pheasant	40,724,645	184,947,831	225,672,476	—	—	—	—	56
1272 pheasant		2,201,755	2,201,755					57
1272 pheasant		2,522,092	2,522,092					58
1272 pheasant		1,352,825	1,352,825					59
1272 pheasant		1,994,757	1,994,757					60
ASCR		882,836	882,836					61
1272 pheasant	42,596	8,925,830	8,968,426					62
1272 pheasant		1,522,381	1,522,381					63
1272 pheasant		7,864,339	7,864,339					64
1272 pheasant		4,069,483	4,069,483					65
1272 pheasant		8,835,363	8,835,363				—	66
ACSR		10,369,988	10,369,988					67
ACSR		930,556	930,556					68
				364,647	16,410,672	792,716	17,568,034	69
—	105,001,078	843,984,581	948,985,659	364,647	16,410,672	792,716	17,568,034	70

Page 422.1, Row 64, Column (a)

1. Line owned: 33.3% Public Service Co. of NM; 66.7% El Paso Electric Co. (not an associated company). Operating and maintenance expenses are shared on the same basis as ownership.
2. Line owned: 5.36% Public Service Co. of NM; 94.364% Tucson Electric Power Co. (not an associated company). Operating and maintenance expenses are shared on the same basis as ownership.
3. Line owned: 50% Public Service Co. of NM; 50% Tucson Electric Power Co. (not an associated company). Operating and maintenance expenses are shared on the same basis as ownership.
4. Line owned: 60% Public Service Co. of NM; 40% El Paso Electric Co. (not an associated company). Operating and maintenance expenses are shared on the same basis as ownership.
5. Line owned: 42.8% Public Service Co. of NM; 57.2% El Paso Electric Co. (not an associated company) Operating and maintenance expenses are shared on the same basis as ownership.
6. Line owned: 9.55% Public Service Co. of NM; 18.72% El Paso Electric Co. (not an associated company); 34.6% Arizona Public Service (not an associated company); 37.13% Salt River Project (not an associated company). Operating and maintenance expenses are shared on the same basis as ownership.
7. Line owned: 5.36% Public Service Co. of NM; 94.64% Tucson Electric Power Co. (not an associated company). Operating and maintenance expenses are shared on the same basis as ownership.
8. Line owned: 94% Public Service Co. of NM; 6% City of Farmington. Operating and maintenance expenses are shared on the same basis as ownership.
9. Line owned: 2.49% Public Service Co. of NM; 18.7% El Paso Electric Co. (not an associated company); 31.46% Arizona Public Service (not an associated company); 47.35% Salt River Project (not an associated company). Operating and maintenance expenses are shared on the same basis as ownership.
10. Purchased from Tri-State in February 2001 at 100% ownership.
11. Purchased from Western Spirit Transmission, LLC in December 2021.

Note: Transmission Line Expenses include accounts 563, 564, 571 and 572 with allocations of 560, 566, 568 and 573.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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 (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Hidden Mountain	Rattlesnake	4.80	Steel		1	
2	Pillar	Four Corners	1.12	Steel		1	
3							
4							
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41							
42							
43							
44	TOTAL		5.92		—	2.00	—

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 (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
115					7,847,296	2,522,693	—	10,369,988	1
230					626,387	304,169	—	930,556	2
								—	3
								—	4
								—	5
								—	6
								—	7
								—	8
								—	9
								—	10
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								—	38
								—	39
								—	40
								—	41
								—	42
								—	43
				—	8,473,682.76	2,826,861.91	—	11,300,544.6	44

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Albuquerque Division:				
2	Alcazar	Distribution	115.00	12.47	
3	Anderson	Distribution	115.00	12.47	
4	Arno	Distribution	46.00	12.47	
5	Aspen	Distribution	115.00	12.47	
6	Ball Park	Distribution	46.00	4.16	
7	Bel-Air	Distribution	115.00	12.47	
8	Beverly Wood	Distribution	115.00	12.47	
9	Black Ranch	Distribution	115.00	12.47	
10	Blackwater 1a	Transmission	345.00	60.00	
11	Blackwater 1b	Transmission	230.00	60.00	
12	Blackwater 1c	Transmission	345.00		
13	Britton	Transmission	115.00		
14	Cabezon	Transmission	345.00	115.00	
15	Central	Distribution	115.00	12.47	
16	Cibola	Transmission	115.00		
17	Claremont	Distribution	115.00	12.47	
18	Clines Corners	Transmission	345.00		
19	Coal	Distribution	115.00	12.47	
20	Cornell	Distribution	115.00	12.47	
21	Cottonwood	Distribution	115.00	12.47	
22	Diamond Tail	Transmission	345.00		
23	Eastridge	Distribution	115.00	12.47	
24	Embudo	Transmission	115.00		
25	Embudo	Distribution	115.00	12.47	
26	Four Hills	Distribution	115.00	12.47	
27	Girard	Distribution	115.00	12.47	
28	Guadalupe	Transmission	345.00		
29	Hamilton	Distribution	115.00	12.47	
30	Hawkins	Distribution	115.00	12.47	
31	Hazeldine	Distribution	46.00	4.16	
32	Indian Hospital	Distribution	115.00	12.47	
33	Inez	Distribution	115.00	12.47	
34	Innovation	Distribution	115.00	12.47	
35	Iron Street	Distribution	46.00	12.47	
36	Irving	Transmission	115.00		
37	Jefferson	Distribution	115.00	4.16	
38	Juan Tabo	Distribution	115.00	12.47	
39	Keleher	Distribution	46.00	4.16	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	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 Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
22	1					2
11	1					3
28	2					4
22	1					5
5	1					6
22	1					7
14	1					8
34	1					9
243	3	1				10
219	3	1				11
			Synchronous	1		12
83	1					13
238	1					14
22	1					15
						16
22	1					17
						18
22	1					19
22	1					20
67	2					21
						22
22	1					23
						24
22	1					25
22	1					26
20	1					27
			SVC	1		28
45	2					29
45	2					30
5	1					31
22	1					32
14	1					33
34	1					34
40	2					35
						36
14	1					37
22	1					38
6	1					39

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	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 (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
40	Kirtland	Transmission	115.00		
41	La Morada	Distribution	115.00	12.47	
42	Lawrence	Distribution	115.00	12.47	
43	Lenkurt	Distribution	115.00	12.47	
44	Leyendecker	Distribution	115.00	12.47	
45	Lomas	Distribution	115.00	12.47	
46	Los Angeles	Distribution	115.00	12.47	
47	Lost Horizon	Distribution	115.00	12.47	
48	Louden Hills	Distribution	115.00	12.47	
49	Manzanita	Distribution	46.00	12.47	
50	Mariposa	Distribution	115.00	12.47	
51	Menaul	Distribution	115.00	12.47	
52	Mission	Transmission	115.00		
53	Mission	Distribution	115.00	12.47	
54	Mobile Sub #T-117	Distribution	115.00	13.80	
55	Mobile Sub #T-57	Distribution	46.00	12.50	
56	Mobile Sub #T-59	Distribution	115.00	13.80	
57	Montano	Distribution	115.00	12.47	
58	Montgomery Plaza	Distribution	115.00	12.47	
59	Morris	Distribution	115.00	12.47	
60	North	Transmission	115.00		
61	North	Distribution	115.00	12.47	
62	Ortiz	Distribution	115.00	12.47	
63	Pajarito	Transmission	345.00		
64	Paradise Hills	Distribution	115.00	12.47	
65	Person Station	Distribution	115.00	46.00	
66	Person Station	Transmission	115.00		
67	Petroglyph	Transmission	115.00		
68	Petroglyph	Distribution	115.00	12.47	
69	Prager	Distribution	115.00	12.47	
70	Prager	Transmission	115.00		
71	Prager Station	Distribution	115.00	46.00	
72	Princess Jeanne	Distribution	115.00	12.47	
73	Prosperity	Distribution	115.00	12.47	
74	Red Mesa	Transmission	115.00		
75	Reeves	Transmission	115.00		
76	Reeves	Distribution	115.00	12.47	
77	Richmond	Transmission	115.00		
78	Rita	Distribution	115.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						40
34	1					41
22	1					42
20	1					43
22	1					44
37	1					45
14	1					46
34	1					47
7	1					48
30	2					49
22	1					50
34	1					51
						52
67	2					53
25	1					54
7	1					55
17	1					56
22	1					57
34	1					58
34	1					59
						60
45	2					61
22	1					62
						63
20	1					64
80	1					65
						66
						67
34						68
34	1					69
						70
80	1					71
22	1					72
34	1					73
						74
						75
22	1					76
						77
14	1					78

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
79	Roy	Distribution	115.00	12.47	
80	Sagebrush	Distribution	115.00	12.47	
81	San Pedro	Distribution	115.00	12.47	
82	Sandia Sw. Sta.	Distribution	115.00	46.00	
83	Sandia Sw. Sta.	Transmission	345.00	115.00	
84	Scenic	Transmission	115.00		
85	Scenic	Distribution	115.00	12.47	
86	Sewer Plant	Distribution	115.00	12.47	
87	Signetics	Distribution	115.00	12.47	
88	Snow Vista	Transmission	115.00		
89	Snow Vista	Distribution	115.00	12.47	
90	South Coors	Distribution	115.00	12.47	
91	St. Cecilia	Distribution	115.00	12.47	
92	St. Joseph	Distribution	115.00	12.47	
93	Studio	Distribution	115.00	12.47	
94	Taiban Mesa	Transmission	345.00		
95	Thomas	Distribution	115.00	12.47	
96	Tramway	Distribution	115.00	12.47	
97	Truman	Distribution	115.00	12.47	
98	Unser	Distribution	115.00	12.47	
99	Volcano	Distribution	115.00	12.47	
100	Wayne	Distribution	115.00	12.47	
101	Wesmeco	Distribution	115.00	12.47	
102	West Mesa Sw. Sta. 1a	Transmission	230.00	115.00	
103	West Mesa Sw. Sta. 1b	Transmission	345.00	115.00	
104	Western Spirit	Transmission	345.00		
105	Winrock	Distribution	115.00	12.47	
106	Wyoming	Distribution	115.00	12.47	
107	Belen, NM Division:				
108	Bosque Farms	Distribution	115.00	12.47	
109	College	Transmission	115.00		
110	College	Distribution	115.00	12.47	
111	El Cerro	Transmission	115.00		
112	El Cerro	Distribution	115.00	12.47	
113	First Street	Distribution	115.00	12.47	
114	Huning Ranch	Transmission	115.00		
115	Isleta	Distribution	46.00	12.47	
116	Jarales	Distribution	115.00	12.47	
117	Los Chavez	Distribution	46.00	12.47	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	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)	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)	
34	1					79
67	2					80
34	1					81
160	2					82
448	1	1				83
						84
34	1					85
22	1					86
83	2					87
						88
34	1					89
22	1					90
22	1					91
22	1					92
34	1					93
						94
22	1					95
22	1					96
22	1					97
34	1					98
67	2					99
67	2					100
22	1					101
400	2					102
898	2					103
						104
22	1					105
34	1					106
						107
6	1					108
						109
22	1					110
						111
14	1					112
22	1					113
						114
6	1					115
22	1					116
14	1					117

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	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 (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
118	Los Lunas	Distribution	46.00	12.47	
119	Los Morros	Transmission	115.00		
120	Los Morros	Distribution	115.00	12.47	
121	Manzano	Distribution	115.00	12.47	
122	Palace	Distribution	115.00	12.47	
123	Quail Ranch	Transmission	345.00		
124	Rattlesnake	Transmission	115.00	34.50	
125	Rattlesnake.	Transmission	115.00	12.47	
126	Sky Ranch	Transmission	115.00		
127	Tome	Transmission	115.00		
128	Tome	Distribution	115.00	12.47	
129	Tome Sw. Sta.	Distribution	115.00	46.00	
130	Bernalillo, NM Division:				
131	Algodones	Transmission	115.00		
132	Algodones	Distribution	115.00	12.47	
133	Avila	Distribution	115.00	12.47	
134	BA Sw. Sta.	Transmission	345.00	115.00	
135	Corrales Bluff	Transmission	115.00		
136	Corrales Bluff	Distribution	115.00	12.47	
137	Cuchilla	Distribution	115.00	4.16	
138	Enchanted Hills	Distribution	115.00	12.47	
139	Iris	Distribution	115.00	12.47	
140	North Bernalillo	Distribution	115.00	12.47	
141	Pachman	Transmission	115.00		
142	Pachmann	Distribution	115.00	12.47	
143	Palm	Distribution	115.00	12.47	
144	Progress	Distribution	115.00	12.47	
145	Panorama	Distribution	115.00	12.47	
146	Rio Hondo	Distribution	115.00	12.47	
147	Sara	Distribution	115.00	12.47	
148	Veranda	Distribution	115.00	12.47	
149	Rio Puerco Sw. Sta.	Transmission	345.00	115.00	
150	Clayton, NM Division:				
151	Van Buren 1a	Distribution	69.00	12.47	
152	Van Buren 1b	Distribution	12.47	4.16	
153	Van Buren 1c	Distribution	69.00	4.16	
154	Deming, NM Division				
155	Deming East and West	Distribution	115.00	13.80	
156	Gold Street	Distribution	115.00	13.80	
157	Hermanas	Distribution	115.00	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
6	1					118
						119
45	2					120
14	1					121
14	1					122
300	1					123
240	3					124
34	1					125
190	1					126
						127
13	1					128
44	1					129
						130
						131
20	2					132
20	1					133
448	1					134
						135
33.6	1					136
14	1					137
22	1					138
34	1					139
14	1					140
						141
33.6	1					142
22	1					143
34	1					144
22	1					145
22	1					146
323	8					147
56	2					148
450	1		SVC	1		149
						150
11	1					151
6	1					152
6	1					153
						154
18	2					155
22	1					156
20	1					157

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	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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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
158	Hondale	Distribution	115.00	13.80	
159	Luna Sw. Sta.	Transmission	345.00	115.00	
160	Mimbres	Transmission	115.00		
161	East Mountains Division:				
162	Ideal Unit	Distribution	46.00	4.16	
163	San Antonito	Distribution	46.00	12.47	
164	Tijeras	Distribution	46.00	12.47	
165	Zamora	Distribution	46.00	12.47	
166	Las Vegas, NM Division:				
167	Arriba	Distribution	115.00	12.47	
168	Baca	Distribution	46.00	12.47	
169	Valencia Sw. Sta.	Distribution	115.00	46.00	
170	Galinas	Distribution	115.00	12.47	
171	San Juan, NM Division:				
172	San Juan GS	Distribution	12.47	4.16	
173	San Juan Mining	Distribution	345.00	69.00	
174	San Juan	Distribution	230.00	69.00	
175	San Juan	Transmission	345.00	230.00	
176	Pillar	Transmission	230.00		
177	Jicarilla	Transmission	345.00		
178	Santa Fe, NM Division:				
179	Alire	Distribution	46.00	12.47	
180	Beckner Road	Distribution	115.00	12.47	
181	Buckman	Distribution	115.00	12.47	
182	Caja Del Rio	Distribution	115.00	12.47	
183	Camel Tracks	Distribution	46.00	12.47	
184	Capital	Distribution	46.00	4.16	
185	Cochiti	Distribution	46.00	12.47	
186	Colinas	Distribution	115.00	12.47	
187	El dorado	Distribution	115.00	12.47	
188	Ft. Marcy	Distribution	46.00	12.47	
189	Halona	Distribution	46.00	4.16	
190	Hickox	Distribution	46.00	4.16	
191	Kaiser	Distribution	46.00	4.16	
192	Kewa	Distribution	115.00	12.47	
193	La Bajada	Distribution	46.00	12.47	
194	Manhattan	Distribution	46.00	12.47	
195	Mejia	Distribution	115.00	12.47	
196	Miquel A. Lujan	Distribution	46.00	12.47	
197	Norton	Transmission	345.00	115.00	

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
14	1					158
224	1					159
						160
						161
19	3					162
13	2					163
14	1					164
22	1					165
						166
22	1					167
6	1					168
20	1					169
22	1					170
						171
18	1					172
168	1					173
30	1					174
400	1					175
						176
						177
						178
7	1					179
22	1					180
29	2					181
34	1					182
8	1					183
4	1					184
6	1					185
14	1					186
22	1					187
22	1					188
5	1					189
5	1					190
5	1					191
14	1					192
1	3					193
7	1					194
22	1					195
22	1					196
448	1					197

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	End of 2025/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
198	Ojo Sw. Sta.	Transmission	345.00	115.00	
199	Pecos	Distribution	46.00	12.47	
200	Peralta	Distribution	46.00	12.47	
201	Rodeo	Distribution	115.00	12.47	
202	S.F. Power Plant	Distribution	46.00	4.16	
203	Santo Domongo	Distribution	46.00	12.47	
204	South Pacheco	Distribution	115.00	12.47	
205	State Pen	Distribution	115.00	12.47	
206	Warner	Distribution	46.00	12.47	
207	Zafarano	Distribution	115.00	12.47	
208	Zia Sw. Sta.	Transmission	115.00		
209	Zia Sw. Sta	Distribution	115.00	46.00	
210	Western NM Division:				
211	Ambrosia Sw. Sta.	Transmission	230.00	115.00	
212	Church Rock 1	Distribution	115.00	12.47	
213	Gallegos Sw. Sta.	Transmission	230.00	115.00	
214	Marquez	Distribution	115.00	12.47	
215	San Lucas	Distribution	115.00	34.50	
216	United	Distribution	115.00	13.20	
217	Yah-Ta-Hey Sw. Sta.	Transmission	345.00	115.00	
218	Southern NM - Western Division:				
219	Alamogordo Sw. Sta.	Transmission	115.00		
220	Burro Mountain	Distribution	69.00	7.20	
221	Cliff	Distribution	25.00	12.47	
222	Hidalgo	Transmission	345.00	115.00	
223	Lordsburg	Transmission	115.00		
224	Lordsburg	Distribution	115.00	69.00	
225	Lordsburg South	Distribution	69.00	12.47	
226	MD#1	Distribution	115.00	69.00	
227	MD#1 T1	Distribution	69.00	23.00	
228	North Silver	Distribution	69.00	12.47	
229	Picacho	Transmission	115.00		
230	Silver City Sub	Distribution	69.00	12.47	
231	Turquoise	Transmission	115.00		
232	Turquoise	Distribution	115.00	69.00	
233	Tyrone	Distribution	69.00	7.20	
234	Southern NM - Eastern Division:				
235	Alamogordo	Distribution	115.00	12.47	
236	Tularosa	Distribution	115.00	12.47	
237	Hollywood	Distribution	115.00	12.47	
238	Gavilan	Distribution	115.00	12.47	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	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: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
300	1					198
7	1					199
6	1					200
20	1					201
6	1					202
3	1					203
45	2					204
14	1					205
11	1					206
34	1					207
						208
146	3					209
						210
224	1					211
13	1					212
100	1					213
14	1					214
28	1					215
28	1					216
524	2					217
						218
						219
1	2					220
	2					221
424	2					222
						223
27	1					224
19	2					225
36	1					226
22	3					227
20	1					228
						229
29	2					230
						231
59	1					232
4	3					233
						234
106	3					235
22	1					236
23	2					237
19	1					238

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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 (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
239	TOTAL Transmission Substations				
240	TOTAL Distribution Substations				
241	TOTAL Generation Substations				
242	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2026	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)	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)	
					—	239
						240
						241
					—	242

FOOTNOTE DATA

Page 426, Row 1, Column (b)

* Dedicated
** Tertiary

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Public Service Company of New Mexico	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr) 04/17/2026	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	Service billings	TXNM Energy Inc.	182,922	133,409,149
3	Interest payments	TXNM Energy Inc.	430,431	249,996
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Call center	Texas-New Mexico Power Co	901	266,955
22	Dispatch services	Texas-New Mexico Power Co	903	44,313
23	Interest billings	TXNM Energy Inc.	419	527,491
24				
25				
26				
27				
28				
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