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

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) Northern Indiana Public Service Company LLC	Year/Period of Report End of: 2025/ Q4

FERC FORM NO. 1 (REV. 02-04)

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

GENERAL INFORMATION

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.

Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others 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:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

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

What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

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

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

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:

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

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.)

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

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 [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF 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.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

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 https://www.ferc.gov/general-information-0/electric-industry-forms.

When to Submit

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

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

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

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

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.

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.

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).

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.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

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

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.

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

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

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.

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:

'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;

'Person' means an individual or a corporation;

'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;

'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; ......

"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

'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.

Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by 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 shall 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 any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

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.

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.

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
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Northern Indiana Public Service Company LLC	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) 801 E. 86th Avenue, Merrillville, IN 46410	
05 Name of Contact Person Lacey Doles	06 Title of Contact Person Controller
07 Address of Contact Person (Street, City, State, Zip Code) 290 W. Nationwide Blvd., Columbus, OH 43215	

08 Telephone of Contact Person, Including Area Code (380) 268-2949	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/20/2026

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 Gunnar J. Gode	03 Signature /s/ Gunnar J. Gode	04 Date Signed (Mo, Da, Yr) 04/20/2026
02 Title SVP Chief Accounting and Tax Officer		

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: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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".

43	**Regional Transmission Service Revenues (Account 457.1)**	302	none
44	**Sales of Electricity by Rate Schedules**	304	
45	**Sales for Resale**	310	
46	**Electric Operation and Maintenance Expenses**	320	
47	**Purchased Power**	326	
48	**Transmission of Electricity for Others**	328	
49	**Transmission of Electricity by ISO/RTOs**	331	none
50	**Transmission of Electricity by Others**	332	none
51	**Miscellaneous General Expenses-Electric**	335	
52	**Depreciation and Amortization of Electric Plant (Account 403, 404, 405)**	336	
53	**Regulatory Commission Expenses**	350	
54	**Research, Development and Demonstration Activities**	352	
55	**Distribution of Salaries and Wages**	354	
56	**Common Utility Plant and Expenses**	356	
57	**Amounts included in ISO/RTO Settlement Statements**	397	
58	**Purchase and Sale of Ancillary Services**	398	
59	**Monthly Transmission System Peak Load**	400	
60	**Monthly ISO/RTO Transmission System Peak Load**	400a	
61	**Electric Energy Account**	401a	
62	**Monthly Peaks and Output**	401b	
63	**Steam Electric Generating Plant Statistics**	402	
63.1	**Renewable Generating Plant Statistics**	404	
64	**Hydroelectric Generating Plant Statistics**	406	none
65	**Pumped Storage Generating Plant Statistics**	408	none
66	**Generating Plant Statistics Pages**	410	
66.1	**Energy Storage Operations (Large Plants)**	414	
66.2	**Energy Storage Operations (Small Plants)**	419	
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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.

Gunnar J. Gode

801 E. 86th Avenue, Merrillville, IN 46410

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.

State of Incorporation: IN

Date of Incorporation: 1912-08-02

Incorporated Under Special Law:

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.

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

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

Electric and Gas Utility Services in the state of Indiana.

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

(2) ☑ No

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

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.

Northern Indiana Public Service Company LLC is a wholly-owned subsidiary of NIPSCO Holdings II LLC.

NIPSCO Holdings II LLC is owned by NIPSCO Holdings I LLC (80.1%) and BIP Blue Buyer LLC (19.9%).

NIPSCO Holdings I, LLC is a wholly-owned subsidiary of NiSource Inc.

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	NIPSCO Accounts Receivable Corp.	Financing	100	
2	Rosewater Wind Generation LLC (1)	Wind Generation		see Note (1) below
3	Indiana Crossroads Wind Generation LLC (2)	Wind Generation		see Note (2) below
4	Indiana Crossroads Solar Generation LLC (3)	Solar Generation		see Note (3) below
5	Dunn's Bridge I Solar Generation LLC (4)	Solar Generation		see Note (4) below
6	(1) Rosewater Wind Generation LLC is a joint venture, which includes NIPSCO as a managing partner, Wells Fargo as the tax equity partner and EDPR as the developer. As the managing partner, NIPSCO controls decisions that are significant to the ongoing operations and economic results of Rosewater Wind Generation, LLC.			
7	(2) Indiana Crossroads Wind Generation LLC is a joint venture, which includes NIPSCO as a managing partner, JPM Capital Corporation as the tax equity partner and EDPR as the developer. As the managing partner, NIPSCO controls decisions that are significant to the ongoing operations and economic results of Indiana Crossroads Wind Generation, LLC.			
8	(3) Indiana Crossroads Solar Generation LLC is a joint venture, which includes NIPSCO as a managing partner, U.S. Bancorp Community Development Corporation as the tax equity partner and EDPR as the developer. As the managing partner, NIPSCO controls decisions that are significant to the ongoing operations and economic results of Indiana Crossroads Solar Generation, LLC.			
9	(4) Dunn's Bridge I Solar Generation LLC is a joint venture, which includes NIPSCO as a managing partner, Wells Fargo Bank as the tax equity partner and NextEra as the developer. As the managing partner, NIPSCO controls decisions that are significant to the ongoing operations and economic results of Dunn's Bridge I Solar Generation, LLC.			

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	VP Supply & Optimization	Karl E. Stanley	148,244		
2	VP Gas Operations	Karima Hasan Bey	284,625		
3	VP Rates & Regulatory Strategy	Jennifer L. Shikany	105,494		
4	EVP General Counsel & Corporate Secretary	Kimberly S. Cuccia	203,280		
5	EVP & Chief Financial Officer	Shawn Anderson	261,360		
6	VP Regulatory & Major Accounts	Erin E. Whitehead	256,500		
7	President & COO	Vincent A. Parisi	443,330		
8	SVP Construction	James E. Zucal	149,313		
9	SVP Chief Accounting and Tax Officer	Gunnar J. Gode	137,456	2025-08-01	
10	VP Chief Accounting Officer and Controller	Gunnar J. Gode (Previously)			2025-07-31
11	EVP & Group President Utilities	Melody Birmingham	249,711		
12	EVP, Technology, Customer and Chief Commercial Officer	Michael Luhrs	251,680	2025-04-01	
13	EVP, Strategy and Risk	Michael Luhrs (Previously)			2025-03-31
14	VP Treasurer & Corporate Finance	Tchapo Napoe	120,032		
15	SVP Electric Operations	Orville Cocking	376,434		2025-08-18
16	VP Power Delivery	David Walter	279,053		2025-01-12
17	VP Tax	Jennifer Harding	103,634		2025-08-25
18	VP & DGC Corporate	John Nassos	132,784		2025-06-30
19	VP Electric Generation	Brian McCaul	320,850	2025-01-13	
20	VP Power Delivery	Vincent Ransom	317,750	2025-01-13	
21	SVP Electric Operations	Rufus Jackson	412,600	2025-11-01	

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
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Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

INFORMATION ON FORMULA RATES

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 (a)	FERC Proceeding (b)
1	Attachment GG:	
2	Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER06-18-000
3	Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER06-18-008
4	Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER09-15-000
5	Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER09-91-000
6	Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER09-506-000
7	Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER09-1431-000
8	Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER09-1657-000
9	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER10-1997-000
10	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER10-1997-001
11	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER11-28-000
12	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER11-134-000
13	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER11-28-001
14	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER11-2565-000
15	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER11-3279-000
16	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-334-000
17	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-480-000
18	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER13-674-000
19	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-261-000
20	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-421-000
21	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER11-3279-001
22	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-1313-000
23	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-1534-000
24	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-867-000
25	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER22-90-000
26	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER25-323-000
27	Attachment O:	
28	Midwest ISO FERC Electric Tariff Original Volume No. 1	ER98-1438-000
29	Midwest ISO FERC Electric Tariff First Revised Volume No. 1	ER98-1438-007
30	Midwest ISO FERC Electric Tariff Second Revised Volume No. 1	ER04-458-004
31	Midwest ISO FERC Electric Tariff Second Revised Volume No. 1	ER04-895-000
32	Midwest ISO FERC Electric Tariff Second Revised Volume No. 1	ER05-122-000
33	Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER05-1085-001; ER04-458-008
34	Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER04-691-014; EL04-104-013; EL04-104-032
35	Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER04-691-034; EL04-104-013; EL04-104-032
36	Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER06-159-000
37	Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER07-113-000
38	Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER07-113-002
39	Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	OA08-4-001

40	Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER09-15-001
41	Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER09-91-000; ER09-573-000
42	Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER09-1779-000
43	Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER10-1492-000
44	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER11-2700-000
45	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER11-2700-004
46	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER11-3251-000
47	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER11-3704-000
48	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-297-000
49	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-310-000
50	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-578-000
51	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-1667-000
52	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER13-307-000
53	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER13-674-002
54	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-1547-000
55	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-1827-000
56	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-2379-000
57	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-102-000
58	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-421-000 and ER14-421-001
59	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-260-000
60	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-649-000
61	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-2379-003
62	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-142-000
63	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-277-000
64	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-358-000
65	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-2379-004
66	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1067-000
67	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1210-000
68	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1490-000
69	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1067-001
70	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-314-000
71	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1210-001
72	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-2364-000
73	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-18-000
74	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-1322-000
75	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-1333-000
76	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-215-001
77	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-893-000
78	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-2323-000
79	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-2323-001
80	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-94-000
81	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-788-000
82	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-1159-000
83	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-1982-000
84	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-249-000
85	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-652-000
86	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-2050-000
87	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-2050-002
88	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER20-1167-000

89	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-200-000
90	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-262-000
91	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-1510-000
92	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-1516-000
93	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER22-1602-000
94	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-2050-000
95	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-2133-000
96	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER22-2768-000
97	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER23-2707-000
98	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER25-324-000
99	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER25-2304-000
100	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER25-2600-000
101	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER25-3074-000
102	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER26-371-000
103	Attachment MM:	
104	Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER10-1791
105	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-312-000
106	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-450-000
107	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-480-002
108	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-480-003
109	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-715-000
110	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-715-002
111	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER13-263-001
112	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER13-1169-000
113	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-1169-001
114	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-2468-000
115	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER12-480-006
116	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER12-480-007
117	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1689-000
118	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-392-000
119	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-2417-000
120	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-465-000
121	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER22-1579-000
122	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER23-1532-000
123	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER23-2311-000

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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

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

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20302-5323	03/02/2026	ER26-1589-000	Annual Informational Attachment O filing	MISO, Inc. - FERC Tariff

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

INFORMATION ON FORMULA RATES - Formula Rate Variances

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

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
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Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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 Pages 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.

1. None

2. None

3. In January 2025, Fairbanks achieved mechanical completion, resulting in NIPSCO making a $336.6 million payment to the developer. The company recorded a liability totaling $144.1 million on the Condensed Consolidated Balance Sheets (unaudited) as other accruals, which will be paid to the developer upon substantial completion. In January 2025, Dunns Bridge II achieved substantial completion, resulting in NIPSCO making a $217.6 million payment to the developer in February 2025. No communication to the Commission was required. Gibson achieved mechanical completion in June 2025 and substantial completion in August 2025. Upon mechanical completion, NIPSCO made a $262.4 million payment to the developer, while accruing $134.6 million for substantial completion to be paid in September 2025. In May 2025, Fairbanks achieved substantial completion, resulting in NIPSCO making a $141.4 million payment to the developer in June 2025. In August 2025, the Gibson project achieved substantial completion, resulting in NIPSCO making a $133.7 million payment to the developer in September 2025. In December 2025, Fairbanks achieved final completion, which resulted in NIPSCO making a $2.7 million payment.

4. Upon mechanical completion of Fairbanks on January 8,2025, NIPSCO entered into 33 agreements with private landowners with lease terms of 30 years. In 2025, NIPSCO will pay $2.25 million for leaseholds and easements to the properties. Fairbanks Generating Asset and corresponding leases were included in NIPSCO's pending base rate case in Cause No. 46120 filed with the Indiana Utility Regulatory Commission on September 12, 2024. Upon mechanical completion of Gibson on June 18, 2025, NIPSCO entered into 21 agreements with private landowners with lease terms of 30 years. In 2025, NIPSCO will pay $1.47 million for leaseholds and easements to the properties, which are subject to a 2% annual escalation each year.

5. None

6. On March 31, 2025, June 30,2025, September 30 2025, and December 31, 2025, NIPSCO issued intercompany notes in the amounts of $525 million, $100 million, $100 million, and $50 million, respectively.

7. None

8. None

9. Refer to page 123 - Notes to Financial Statements, Note 17-C, "Other Commitments and Contingencies - Legal Proceedings" for more information.

10. None

12. None

13. Refer to page 104 for officer changes.

14. N/A

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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	18,691,955,252	15,591,315,144
3	Construction Work in Progress (107)	200	1,273,509,253	1,677,273,252
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		19,965,464,505	17,268,588,396
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	5,889,136,698	5,616,966,490
6	Net Utility Plant (Enter Total of line 4 less 5)		14,076,327,807	11,651,621,906
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		14,076,327,807	11,651,621,906
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)		4,949,422	4,949,422
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		4,933,199	396,983
19	(Less) Accum. Prov. for Depr. and Amort. (122)		243,667	243,667
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	12,931,641	31,400,537
23	Noncurrent Portion of Allowances and Environmental Credits	228		
24	Other Investments (124)		41,396	41,396
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)			
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)		8,809,085	16,589,196
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		26,471,654	48,184,445
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		3,514,592	16,760,104
36	Special Deposits (132-134)		21,566,588	23,651,647
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		23,355,882	25,080,531
41	Other Accounts Receivable (143)		43,388,388	30,685,988
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		6,590,714	883,878
43	Notes Receivable from Associated Companies (145)		214,484,673	101,391,696
44	Accounts Receivable from Assoc. Companies (146)		43,919,358	151,335,446
45	Fuel Stock (151)	227	7,244,233	30,296,797
46	Fuel Stock Expenses Undistributed (152)	227	1,277,096	5,903,307
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	176,998,949	155,625,569

49	Merchandise (155)	227	8,498	8,083
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances and Environmental Credits (158.1, 158.2, 158.3, and 158.4)	228		
53	(Less) Noncurrent Portion of Allowances and Environmental Credits	228		
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)		73,681,519	48,759,071
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		4,454,675	10,419,657
57	Prepayments (165)		66,655,962	59,329,908
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)		431,908	461,981
61	Accrued Utility Revenues (173)			
62	Miscellaneous Current and Accrued Assets (174)		873,019	648,724
63	Derivative Instrument Assets (175)		16,924,197	24,470,361
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		8,809,085	16,589,196
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)		683,379,738	667,355,796
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)			
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	1,875,422,170	1,928,444,400
73	Prelim. Survey and Investigation Charges (Electric) (183)		7,232,413	2,974,146
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			10,900,448
75	Other Preliminary Survey and Investigation Charges (183.2)		15,645,717	
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	90,969,100	72,492,260
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)			
82	Accumulated Deferred Income Taxes (190)	234	364,561,308	320,338,551
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		2,353,830,708	2,335,149,805
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		17,144,959,329	14,707,261,374

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250	859,487,917	859,487,917
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)			
7	Other Paid-In Capital (208-211)	253	2,629,153,094	1,831,741,159
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b	469,622	469,622
11	Retained Earnings (215, 215.1, 216)	118	3,737,148,539	3,469,120,362
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	4,338,590	22,807,486
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(2,257)	18,910
16	Total Proprietary Capital (lines 2 through 15)		7,229,656,261	6,182,706,212
17	**LONG-TERM DEBT**			
18	Bonds (221)	256		
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256	5,076,000,000	4,376,000,000
21	Other Long-Term Debt (224)	256	58,000,000	58,000,000
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		20,716	35,224
24	Total Long-Term Debt (lines 18 through 23)		5,133,979,284	4,433,964,776
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		119,970,697	81,767,371
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		248,341	371,823
29	Accumulated Provision for Pensions and Benefits (228.3)		201,545,982	221,640,312
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities		3,749,250	974,951
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		629,853,970	548,795,863
35	Total Other Noncurrent Liabilities (lines 26 through 34)		955,368,240	853,550,320
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)			
38	Accounts Payable (232)		529,793,697	441,605,761
39	Notes Payable to Associated Companies (233)		485,250,000	41,900,000
40	Accounts Payable to Associated Companies (234)		97,865,145	234,050,856
41	Customer Deposits (235)		57,247,367	57,620,745
42	Taxes Accrued (236)	262	73,407,828	163,229,818
43	Interest Accrued (237)		17,773,861	17,622,991
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		15,889,213	13,916,088

48	Miscellaneous Current and Accrued Liabilities (242)		239,490,483	262,811,997
49	Obligations Under Capital Leases-Current (243)		11,440,406	9,590,448
50	Derivative Instrument Liabilities (244)		5,117,666	2,387,651
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		3,749,250	974,951
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)		1,529,526,416	1,243,761,404
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		53,848,855	41,598,286
57	Accumulated Deferred Investment Tax Credits (255)	266	221,219	391,628
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	34,144,000	35,970,927
60	Other Regulatory Liabilities (254)	278	582,025,827	498,284,816
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		1,416,550,902	1,267,229,121
64	Accum. Deferred Income Taxes-Other (283)		209,638,325	149,803,884
65	Total Deferred Credits (lines 56 through 64)		2,296,429,128	1,993,278,662
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		17,144,959,329	14,707,261,374

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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

Do not report fourth quarter data in columns (e) and (f)
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.
Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
Use page 122 for important notes regarding the statement of income for any account thereof.
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 affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
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 purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
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.
Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

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)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	3,273,595,390	2,736,488,938			2,174,023,264	1,898,319,204	1,099,572,125	838,169,734		
3	Operating Expenses											
4	Operation Expenses (401)	320	1,406,803,126	1,194,464,395			797,428,454	721,329,846	609,374,672	473,134,549		
5	Maintenance Expenses (402)	320	201,871,662	199,690,121			150,693,656	144,477,159	51,178,006	55,212,962		
6	Depreciation Expense (403)	336	482,246,523	384,727,965			362,586,546	292,741,463	119,659,977	91,986,502		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336										
8	Amort. & Depl. of Utility Plant (404-405)	336	35,435,082	46,199,258			20,543,421	30,751,543	14,891,661	15,447,715		
9	Amort. of Utility Plant Acq. Adj. (406)	336										
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)											
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		82,319,882	82,260,308			82,319,882	82,260,308				
13	(Less) Regulatory Credits (407.4)											
14	Taxes Other Than Income Taxes (408.1)	262	69,918,622	60,139,828			41,220,841	37,140,857	28,697,781	22,998,971		
15	Income Taxes - Federal (409.1)	262	(14,745,939)	46,809,356			(88,011)	56,729,775	(14,657,928)	(9,920,419)		
16	Income Taxes - Other (409.1)	262	2,307,178	3,764,953			2,112,326	3,879,435	194,852	(114,482)		
17	Provision for Deferred Income Taxes (410.1)	234, 272	402,272,995	189,755,796			314,892,999	117,467,949	87,379,996	72,287,847		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	193,246,445	124,898,460			163,088,424	87,160,706	30,158,021	37,737,754		
19	Investment Tax Credit Adj. - Net (411.4)	266	(170,409)	(217,016)					(170,409)	(217,016)		
20	(Less) Gains from Disp. of Utility Plant (411.6)											

21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)											
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)						(951)		951			
24.1	(Less) Gains from Disposition of Environmental Credits (411.11)											
24.2	Losses from Disposition of Environmental Credits (411.12)											
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24.2)		2,475,012,277	2,082,696,504			1,608,620,739	1,399,617,629	866,391,538	683,078,875		
27	Net Util Oper Inc (Enter Tot line 2 less 25)		798,583,113	653,792,434			565,402,525	498,701,575	233,180,587	155,090,859		
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)											
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		47,147	52,030								
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	(18,468,896)	(12,280,579)								
37	Interest and Dividend Income (419)		12,666,950	11,137,499								
38	Allowance for Other Funds Used During Construction (419.1)		28,166,688	72,444,729								
39	Miscellaneous Nonoperating Income (421)		(12,306,334)	(8,073,618)								
40	Gain on Disposition of Property (421.1)			82,852								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		10,011,261	63,258,853								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)											
44	Miscellaneous Amortization (425)		2,540,514	2,540,514								
45	Donations (426.1)		3,308,721	2,009,947								
46	Life Insurance (426.2)											
47	Penalties (426.3)		1,566,840	372,732								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		398,430	123,746								
49	Other Deductions (426.5)		10,916,913	6,917,336								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		18,731,418	11,964,275								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262										

53	Income Taxes-Federal (409.2)	262	(2,387,956)	89,756								
54	Income Taxes-Other (409.2)	262	(198,610)	70,411								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	1,787,497	201,987								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	53,532,513	9,272,847								
57	Investment Tax Credit Adj.-Net (411.5)											
58	(Less) Investment Tax Credits (420)											
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(54,331,582)	(8,910,693)								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		45,611,425	60,205,271								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		4,433,700	4,433,700								
63	Amort. of Debt Disc. and Expense (428)		14,508	14,508								
64	Amortization of Loss on Reaquired Debt (428.1)											
65	(Less) Amort. of Premium on Debt-Credit (429)											
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)											
67	Interest on Debt to Assoc. Companies (430)		258,042,061	193,641,166								
68	Other Interest Expense (431)		(20,432,515)	710,087								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		22,422,497	24,901,661								
70	Net Interest Charges (Total of lines 62 thru 69)		219,635,257	173,897,800								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		624,559,281	540,099,905								
72	Extraordinary Items											
73	Extraordinary Income (434)											
74	(Less) Extraordinary Deductions (435)											
75	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes-Federal and Other (409.3)	262										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		624,559,281	540,099,905								

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, 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 for 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 for 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, attach them at page 122.

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		3,469,120,362	3,169,739,878
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1	OCI Tax Adjustment			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		643,028,177	552,380,483
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Common Stock Dividend		(375,000,000)	(253,000,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(375,000,000)	(253,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		3,737,148,539	3,469,120,362
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
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)		3,737,148,539	3,469,120,362
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		22,807,486	35,088,065
50	Equity in Earnings for Year (Credit) (Account 418.1)		(18,468,896)	(12,280,579)
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)		4,338,590	22,807,486

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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 Instructions 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)	624,559,281	540,099,905
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	482,246,523	384,727,965
5	Amortization of (Specify) (footnote details)		
5.1	[(a)] Amortization of Electric Utility Plant	102,863,303	113,011,851
5.2	Amortization and Depletion of Gas Utility Plant	14,891,661	15,447,715
8	Deferred Income Taxes (Net)	158,773,794	55,786,476
9	Investment Tax Credit Adjustment (Net)	(170,409)	(217,016)
10	Net (Increase) Decrease in Receivables	(10,917,731)	(100,937,082)
11	Net (Increase) Decrease in Inventory	(11,914,378)	42,796,986
12	Net (Increase) Decrease in Allowances and Environmental Credits Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	(39,609,225)	289,747,503
14	Net (Increase) Decrease in Other Regulatory Assets	18,535,381	29,747,918
15	Net Increase (Decrease) in Other Regulatory Liabilities	83,741,011	(98,931,747)
16	(Less) Allowance for Other Funds Used During Construction	28,166,688	71,244,729
17	(Less) Undistributed Earnings from Subsidiary Companies	(18,468,896)	(12,280,579)
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):	(68,164,154)	191,297,111
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	1,345,137,265	1,403,613,435
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(2,939,401,736)	(2,454,471,296)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant	(51,583,500)	(36,560,782)
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	(28,166,688)	(71,244,729)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(2,962,818,548)	(2,419,787,349)
36	Acquisition of Other Noncurrent Assets (d)	(8,443,027)	
37	Proceeds from Disposal of Noncurrent Assets (d)		
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	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		

51	Net (Increase) Decrease in Allowances and Environmental Credits Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	54,246,564	27,814,349
53	Other (provide details in footnote):		
53.1	Other - Customer Advances for Construction	12,250,569	11,077,078
53.2	Other - Restricted Cash	2,085,059	(871,917)
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(2,902,679,383)	(2,381,767,839)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	775,000,000	725,000,000
62	Preferred Stock		
63	Common Stock	775,932,098	500,000,000
64	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)	443,350,000	22,900,000
67	Other (provide details in footnote):		
67.1	Other: (provide details in footnote):		
67.2	Other: N/A		
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,994,282,098	1,247,900,000
72	Payments for Retirement of:		
73	Long-term Debt (b)	(75,000,000)	
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other - Unamortized Discount on Long-Term Debt	14,508	14,508
76.2	Bond Issuance Costs		
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(375,000,000)	(253,000,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	1,544,296,606	994,914,508
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	(13,245,512)	16,760,104
88	Cash and Cash Equivalents at Beginning of Period	16,760,104	
90	Cash and Cash Equivalents at End of Period	3,514,592	16,760,104

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: NoncashAdjustmentsToCashFlowsFromOperatingActivitiesDescription

Includes accounts 404 & 407.3.

2025

Item 1. Reconciliation of "Other Cash Flows from (used for) Operating Activities.

	2025
Asset Retirement Obligations	81,058,107
Deferred Income Taxes	(106,209,085)
Pensions and Benefits	(20,094,330)
Derivative Instrument Assets/Liabilities	10,320,463
Prepayments	(7,326,054)
Miscellaneous	(25,913,255)
Other - CF Page 120 Line 18.1	**(68,164,154)**

Item 2. Amounts of Interest Paid (net of amounts capitalized) and Income Taxes Paid.

	2025
Income Taxes	(267)
Interest, net of amounts capitalized	264,405,739

Item 3. Reconciliation between "Cash and Cash Equivalents at End of Year".

	2025
Cash - BS Page 110 Line 35	3,514,592
Working Fund - BS Page 110 Line 37	—
Other Special Funds - BS Page 110 Line 28	—
Cash and Cash Equivalents at End of Year - CF Page 121 Line 90	**3,514,592**

Item 4. Non-cash Transactions

	2,025
Settlement of pre-partnership tax payables	67,411,935

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

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, where 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.

This Federal Energy Regulatory Commission (FERC) Form 1 has been prepared in conformity with the 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 Generally Accepted Accounting Principles in the United States of America (GAAP). The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

a. GAAP requires that public business enterprises report certain information about operating segments in complete sets of financial statements of the enterprise and certain information about their products and services, which are not required for FERC reporting purposes.

b. GAAP requires that majority-owned subsidiaries be consolidated for financial reporting purposes. FERC requires that majority-owned subsidiaries be separately reported as Investment in Subsidiary Companies unless an appropriate waiver has been granted by the FERC or authority has been granted for alternative accounting treatment.

c. FERC requires that income or losses of an unusual nature and infrequent occurrence, which would significantly distort the current year's income, be recorded as extraordinary income or deductions, respectively.

d. GAAP requires that the current portion of regulatory assets and regulatory liabilities be reported as current assets and current liabilities, respectively, on the Balance Sheet. FERC requires that the current portion of regulatory assets and liabilities be reported as Regulatory Assets within Deferred Debits and Regulatory Liabilities within Deferred Credits, respectively.

e. GAAP requires that the current portion of long-term debt and preferred stock be reported as a current liability on the Balance Sheet. FERC requires that the current portion of long-term debt and preferred stock be reported as Long-Term Debt and Proprietary Capital.

f. GAAP requires any deferred costs associated with a debt issuance be presented as a reduction to debt on the Consolidated Balance Sheet. FERC requires any Unamortized Debt Expense to be separately states as a Deferred Debit on the Balance Sheet.

g. GAAP requires that certain account balances within financial statement line items which are not in the natural position for that line item (e.g. an account within Accounts Receivable with a credit balance) be reclassed to the appropriate side of the Balance Sheet. FERC does not require certain accounts which are not in a natural position for their respective line item to be reclassed, as long as the line item in total is in its natural position.

h. GAAP requires any deferred costs associated with cloud computing arrangements be presented as non-current assets on the Balance Sheet. FERC requires these deferred costs to be stated as utility plant on the Balance Sheet. The related amortization of these deferred costs is required by GAAP to be presented as operation and maintenance expense on the Statement of Operations. FERC requires presentation of the amortization of these deferred costs as amortization expense in the Statement of Income.

i. As a single-member limited liability company, Northern Indiana Public Service Company LLC (NIPSCO or Respondent) is not a taxable entity for income tax purposes. Following the Minority Interest Transaction, NIPSCO is treated as a component of its parent, NIPSCO Holdings II, LLC (Holdings II), a pass-through entity for U.S. federal and state income tax purposes. The partners in Holdings II are taxed directly on their share of income without regard to distributions, and the partners may generally deduct their share of any losses. However, in accordance with FERC requirements, the accompanying financial statements include entries to reflect income taxes as if NIPSCO were a corporation. Due to this significant difference, we have added FERC only disclosures for Footnote 1.N, Income Taxes and Investment Tax Credits, and Footnote 14, Income Taxes. These FERC only footnotes supersede the respective GAAP disclosures.

j. Where uncertainties exist with respect to income tax positions involving temporary differences, NIPSCO has recorded accumulated deferred income taxes based on the positions taken in the tax returns filed or expected to be filed.

k. GAAP requires assets expected to be retired substantially early to be classified as other property, net of accumulated depreciation, while FERC retains the asset in utility plant until physical retirement, with costs charged to accumulated depreciation at that time.

The Notes to Financial Statements below were published as of March 20, 2026 for the year ended December 31, 2025, and are reported in accordance with GAAP, except for the addition of FERC tax-related Footnotes 1.N and 14 at the end, which supersede the same GAAP footnotes, as discussed above in item i. The Notes include Northern Indiana Public Service Company LLC, NIPSCO Accounts Receivable Corporation, Rosewater Wind Generation LLC, Indiana Crossroads Wind Generation LLC, Indiana Crossroads Solar Generation LLC and Dunn's Bridge I Solar Generation LLC, and as discussed above, these entities are not consolidated for FERC reporting purposes. The Financial Statements that are presented in this Federal Energy Regulatory Commission (FERC) Form 1/3Q do not consolidate those entities and are prepared in conformity with the requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases. However, since the Notes to Financial Statements below are in accordance with GAAP, they do include the required discussion of the consolidated entities.

Defined Terms

The following is a list of frequently used abbreviations or acronyms that are found in this report:

Subsidiaries and Affiliates

NIPSCO ("we," "us" or "our") Northern Indiana Public Service Company LLC
NIPSCO Holdings I NIPSCO Holdings I LLC
NIPSCO Holdings II NIPSCO Holdings II LLC
NiSource NiSource Inc.
NARC NIPSCO Accounts Receivable Corporation
Rosewater Rosewater Wind Generation LLC and its wholly owned subsidiary, Rosewater Wind Farm LLC
Indiana Crossroads Wind Indiana Crossroads Wind Generation LLC and its wholly owned subsidiary, Indiana Crossroads Wind Farm LLC
Indiana Crossroads Solar Indiana Crossroads Solar Generation LLC and its wholly owned subsidiary, Meadow Lake Solar Park LLC
Dunn's Bridge I Dunn's Bridge I Solar Generation LLC and its wholly owned subsidiary, Dunns Bridge Solar Center LLC
Fairbanks Fairbanks Solar Energy Center LLC
Gibson Gibson Solar LLC
GenCo NIPSCO Generation LLC
Generation Holdings II Generation Holdings II LLC

Abbreviations

ADS Amazon Data Services, Inc.
AFUDC Allowance for funds used during construction
AMI Advanced metering infrastructure
ASC Accounting Standards Codification
ASU Accounting Standards Update
BIP BIP Blue Buyer L.L.C.
BIP Blue Buyer VCOC L.L.C. BIP Blue Buyer VCOC L.L.C., a Delaware limited liability company and also an affiliate of Blackstone
BIP Orion Holdco L.P. BIP Orion Holdco L.P., a Delaware limited liability company and also an affiliate of Blackstone
BIP Orion Holdco II L.P. BIP Orion Holdco II L.P., a Delaware limited liability company and also an affiliate of Blackstone
Blackstone Blackstone Infrastructure Partners L.P.
Blackstone Investor BIP Orion Holdco L.P. and BIP Orion Holdco II L.P. affiliates of Blackstone (GenCo Minority Interest Transaction) and Blackstone Infrastructure Partners, affiliates of Blackstone (NIPSCO Minority Interest Transaction)
BTA Build-transfer agreement
CAP Compliance Assurance Process
Cavalry Cavalry Solar Generation Center
CERCLA Comprehensive Environmental Response Compensation and Liability Act (also known as Superfund)
CCRs Coal Combustion Residuals
CPCN Certificate of Public Convenience and Necessity
DSM Demand Side Management
Dunn's Bridge II Dunn's Bridge II Solar Generation
EPA United States Environmental Protection Agency
FASB Financial Accounting Standards Board
FERC Federal Energy Regulatory Commission
GAAP Generally Accepted Accounting Principles
GCA Gas cost adjustment
HLBV Hypothetical Liquidation at Book Value
IRCA Intercompany Revolving Credit Agreement
IRS Internal Revenue Service

IURC Indiana Utility Regulatory Commission
JV Joint Venture
Minority Interest Transaction A Transaction between NiSource, NIPSCO Holdings II (sole owner of NIPSCO) and an affiliate of Blackstone pursuant to a purchase and sale agreement entered into on June 17, 2023, that offered equity interests in NIPSCO Holdings II in exchange for capital contributions by the parties.
MGP Manufactured Gas Plant
MISO Midcontinent Independent System Operator
MMDth Million dekatherms
MW Megawatts
MWh Megawatt hours
NYMEX The New York Mercantile Exchange
OPEB Other Postemployment Benefits
OUCC Indiana Office of Utility Consumer Counselor
PPA Power Purchase Agreement
ROU Right of Use
TCJA Tax Cuts and Jobs Act of 2017
TDSIC Transmission, Distribution and Storage System Improvement Charge
Templeton Templeton Wind Energy Center
VIE Variable Interest Entity
WAM Work and Asset Management enterprise resourcing system.

1. Nature of Operations and Summary of Significant Accounting Policies

A. Company Structure and Basis of Accounting Presentation. NIPSCO is a public utility operating company that supplies natural gas and electric energy to the public. It operates in 31 counties in the northern part of Indiana. NIPSCO's primary operations consist of NIPSCO Gas and NIPSCO Electric. NIPSCO Gas serves approximately 878,000 customers in the northern part of Indiana. NIPSCO Electric generates, transmits and distributes electricity to approximately 497,000 customers and engages in wholesale and transmission transactions. The consolidated financial statements include the accounts of NIPSCO, its subsidiary, NARC, and the consolidation of several joint venture VIEs (Rosewater, Indiana Crossroads Wind, Indiana Crossroads Solar and Dunns Bridge I) after the elimination of all intercompany accounts and transactions.
NiSource, a Delaware corporation, is an energy holding company whose primary subsidiaries are fully regulated natural gas and electric utility companies, serving approximately 3.8 million customers in six states. NIPSCO Holdings II LLC is an indirect subsidiary of NiSource and is sole owner of NIPSCO. NiSource owns an 80.1% controlling equity interest in NIPSCO Holdings II while BIP owns the remaining 19.9% equity interest.

Our management has performed an evaluation of subsequent events through March 20, 2026, which is the date that our consolidated financial statements were available to be issued.

B. Use of Estimates. 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 and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

C. Cash, Cash Equivalents and Restricted Cash. We consider all highly liquid investments with original maturities of three months or less to be cash equivalents. We report amounts deposited in brokerage accounts for margin requirements as restricted cash.

D. Accounts Receivable and Unbilled Revenue. Accounts receivable on the Consolidated Balance Sheets includes both billed and unbilled amounts. Unbilled amounts of accounts receivable relate to a portion of a customer’s consumption of gas or electricity from their last cycle billing date through the last day of the month (balance sheet date). Factors taken into consideration when estimating unbilled revenue include historical usage, customer rates, weather and reasonable and supportable forecasts. Accounts receivable fluctuates from year to year depending in large part on weather impacts and price volatility. Our accounts receivable on the Consolidated Balance Sheets include unbilled revenue, less reserves. The reserve for uncollectible receivables is our best estimate of the amount of probable credit losses in the existing accounts receivable. We determined the reserve based on historical collection experience, current market conditions and reasonable and supportable forecasts. Account balances are charged against the allowance when it is anticipated the receivable will not be recovered. Refer to Note 3, “Revenue Recognition,” for additional information on customer-related accounts receivable, including amounts related to unbilled revenues.

E. Basis of Accounting for Rate-Regulated Operations. Rate-regulated operations account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be billed and collected. Certain expenses and credits subject to utility regulation or rate determination that would normally be reflected in income for non-regulated operations are deferred on the Consolidated Balance Sheets and are later recognized in income as the related amounts are included in customer rates and recovered from or refunded to customers.

We continually evaluate whether or not our operations are within the scope of ASC 980 and rate regulations. As part of that analysis, we evaluate probability of recovery for our regulatory assets. In management’s opinion, we will be subject to regulatory accounting for the foreseeable future. Refer to Note 11, “Regulatory Matters,” for additional information.

F. Plant and Other Property and Related Depreciation and Maintenance. Property, plant and equipment (principally utility plant) is stated at cost. We record depreciation using composite rates on a straight-line basis over the remaining service lives of the electric, gas and common properties, as approved by the IURC.

Renewable generation assets owned by JVs of which we are the primary beneficiary and certain retired regulatory assets as described below, is considered non-utility property and is generally depreciated over the life of the associated assets. Refer to Note 8, “Property, Plant and Equipment,” for additional information related to depreciation expense.

We capitalized AFUDC on all classes of utility property except organization costs, land, autos, office equipment, tools and other general property purchases. AFUDC is applied to construction costs for that period of time between the date of the expenditure and the date on which such project is placed in service. Our consolidated pre-tax rate for AFUDC was 7.0% in 2025, 7.9% in 2024, and 7.0% in 2023.
Generally, we follow the practice of charging maintenance and repairs, including the cost of removal of minor items of property, to expense as incurred. When we retire regulated property, plant and equipment, original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation. However, when it becomes probable a regulated asset will be retired substantially in advance of its original expected useful life or is abandoned, the cost of the asset and the corresponding accumulated depreciation is recognized as a separate asset. If the asset is still in operation, the net amount is classified as “Other property, at cost, less accumulated depreciation” on the Consolidated Balance Sheets. If the asset is no longer operating but still subject to recovery, the net amount is classified in “Regulatory assets” on the Consolidated Balance Sheets. If we are able to recover a full return of and on investment, the carrying value of the asset is based on historical cost. If we are not able to recover a full return on investment, a loss on impairment is recognized to the extent the net book value of the asset exceeds the present value of future revenues discounted at the incremental borrowing rate.

When we retire non-regulated, non-utility property, original cost less salvage value is charged to "Loss (gain) on sale of assets" on the Statements of Consolidated Operations.

External and internal costs associated with on-premises computer software developed for internal use are capitalized. Capitalization of such costs commences upon the completion of the preliminary stage of each project. Once the installed software is ready for its intended use, such capitalized costs are amortized on a straight-line basis generally over a period of five years. External and internal up-front implementation costs associated with cloud computing arrangements that are service contracts are deferred on the Consolidated Balance Sheets, with the associated internal-use software capitalized to plant if we have a contractual right to take possession of the software at any time during the hosting period without significant penalty and it is feasible for us to either run the software on our own hardware or contract with another party unrelated to the vendor to host the software. Once the installed software is ready for its intended use, such deferred costs are amortized on a straight-line basis to “Operation and maintenance,” over the minimum term of the contract plus contractually-provided renewal periods that are reasonably expected to be exercised.

G. Goodwill. Substantially all of our goodwill relates to the excess of cost over the fair value of the net assets acquired in the Northern Indiana Fuel and Light and Kokomo Gas acquisitions in March 1993 and February 1992, respectively. We test our goodwill for impairment annually as of May 1, or more frequently if events and circumstances indicate that goodwill might be impaired. Fair value is determined using a combination of income and market approaches. Refer to Note 9, “Goodwill,” for additional information.

H. Accounts Receivable Transfer Program. We have an agreement with a third party to transfer certain accounts receivable without recourse. These transfers of accounts receivable are accounted for as secured borrowings. The entire gross receivables balance remains on the December 31, 2025 and 2024 Consolidated Balance Sheets. When amounts are securitized, the short-term debt is recorded in the amount of proceeds received from the transferees involved in the transactions. Refer to Note 6, “Short-Term Borrowings,” for further information.

I. Gas Cost and Fuel Adjustment Clause. We defer most differences between gas and fuel purchase costs and the recovery of such costs in revenues and adjust future billings for such deferrals on a basis consistent with applicable IURC-approved tariff provisions. These deferred balances are recorded as “Regulatory assets” or “Regulatory liabilities”, as appropriate, on the Consolidated Balance Sheets. Refer to Note 11, “Regulatory Matters,” for additional information.

J. Gas Storage and Other Inventories. Our natural gas in storage and electric production fuel are valued using the weighted average cost inventory methodology as approved by the IURC. Materials and supplies are valued using the weighted average cost inventory methodology. Materials and supplies are charged to expense or capitalized to property, plant and equipment when issued.

K. Affiliated Company Transactions. We receive executive, financial, information technology, and administrative and general services from an affiliate, NiSource Corporate Services, a wholly owned subsidiary of NiSource. The costs of these services are charged to us based on various approved allocations and consist primarily of employee compensation and benefits and outside services. Operation and maintenance costs totaled $213.5 million, $201.9 million, and $190.2 million for 2025, 2024, and 2023, respectively. Additionally, capitalized costs, which are included in “Utility plant” on the Consolidated Balance
Sheets, totaled $176.1 million and $223.7 million for 2025 and 2024, respectively. Additionally, regulatory-related costs, which are included in “Regulatory Assets” on the Consolidated Balance Sheets, totaled $4.8 million and $16.8 million for 2025 and 2024, respectively.

The amount of federal and state taxes payable to NiSource included in “Taxes accrued” on our Consolidated Balance Sheets was zero as of December 31, 2025 and 2024, respectively. The amount of federal and state taxes receivable from NiSource included in “Income tax receivable” on our Consolidated Balance Sheets was $1.6 million and $0.3 million as of December 31, 2025 and 2024, respectively.

L. Accounting for Exchange and Balancing Arrangements of Natural Gas. We enter into balancing and exchange arrangements of natural gas as part of its operations and off-system sales programs. We record a receivable or payable for any of our respective cumulative gas imbalances, as well as for any gas inventory borrowed or lent under a NIPSCO Gas exchange agreement. Exchange gas is valued based on a particular month's average daily price published by Gas Daily tied to the Chicago City Gate hub. These receivables and payables are recorded as “Exchange gas receivable” or “Other accruals” on our Consolidated Balance Sheets, as appropriate.

M. Accounting for Risk Management Activities. We account for our derivatives and hedging activities in accordance with ASC 815. We recognize all derivatives as either assets or liabilities on our Consolidated Balance Sheets at fair value, unless such contracts are exempted as a normal purchase normal sale under the provisions of the standard. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation.

We do not offset the fair value amounts recognized for any of our derivative instruments against the fair value amounts recognized for the right to reclaim cash collateral or obligation to return cash collateral for derivative instruments executed with the same counterparty under a master netting arrangement. See Note 12, “Risk Management Activities,” for further information.

N. Income Taxes and Investment Tax Credits. NIPSCO's and NARC's business activities through the closing of the Minority Interest Transaction were included in the consolidated U.S. federal and certain state income tax returns of NiSource Inc. Historically, NIPSCO has been treated as a taxable division of our corporate parent, NiSource, Inc., and then as an indirect division of NIPSCO Holdings I effective April 13, 2023. In connection with the Minority Interest Transaction executed on December 31, 2023, NIPSCO Holdings I retained NIPSCO’s income tax balances and 80.1% of the excess deferred income tax regulatory balances. NIPSCO Holdings I’s income tax balances are based on the difference between the financial statement amount and the tax basis of its investment in the NIPSCO Holdings II partnership.

Our financial statements reflect a provision for income taxes through December 31, 2025. For income tax purposes, NIPSCO is a disregarded entity that is wholly owned by the NIPSCO Holdings II partnership, and NIPSCO Accounts Receivable Company (“NARC”) is taxed as a corporation. The provision for income tax expense as of December 31, 2025 and 2024 is attributable to NARC.

Concurrent with the closing of the Minority Interest Transaction, we no longer participate in NiSource’s intercompany tax sharing agreement. Deferred income taxes result from temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. In connection with the Minority Interest Transaction, NIPSCO’s deferred taxes were removed from our GAAP books and were reconstituted as deferred taxes on the outside basis difference of NiSource’s investment in the NIPSCO Holdings II partnership.

O. Pension Remeasurement. We utilize a third-party actuary for the purpose of performing actuarial valuations of our defined benefit plans. Annually, as of December 31, we perform a remeasurement for our defined benefit plans. Quarterly, we monitor for significant events, and if a significant event is identified, we perform a qualitative and quantitative assessment to determine if the resulting remeasurement would materially impact the financial statements. If material, an interim remeasurement is performed. See Note 15, "Pension and Other Postemployment Benefits," for additional information.

P. Environmental Expenditures. We accrue for costs associated with environmental remediation obligations, including expenditures related to asset retirement obligations and cost of removal, when the incurrence of such costs is
probable and the amounts can be reasonably estimated, regardless of when the expenditures are actually made. The estimated future expenditures are based on currently enacted laws and regulations, existing technology and estimated site-specific costs where assumptions may be made about the nature and extent of site contamination, the extent of cleanup efforts, costs of alternative cleanup methods and other variables. The liability is adjusted as further information is discovered or circumstances change. The accruals for estimated environmental expenditures are recorded on the Consolidated Balance Sheets in “Other accruals” for short-term portions of these liabilities and “Other noncurrent liabilities and deferred credits” for the respective long-term portions of these liabilities. We establish regulatory assets on the Consolidated Balance Sheets to the extent that future recovery of environmental remediation costs is probable through the regulatory process. Refer to Note 10, “Asset Retirement Obligations,” and Note 17, “Other Commitments and Contingencies,” for further information.

Q. Excise Taxes. As an agent for some state and local governments, we invoice and collect certain excise taxes levied by state and local governments on customers and record these amounts as liabilities payable to the applicable taxing jurisdiction. Such balances are presented within “Other accruals” on the Consolidated Balance Sheets. These types of taxes collected from customers, comprised largely of sales taxes, are presented on a net basis affecting neither revenues nor cost of sales. We account for excise taxes for which we are liable by recording a liability for the expected tax with a corresponding charge to “Other taxes” expense on the Statements of Consolidated Operations.

R. Accrued Insurance Liabilities. We accrue for insurance costs related to workers compensation, automobile, property, general and employment practices liabilities based on the most probable value of each claim. In general, claim values are determined by professional, licensed loss adjusters who consider the facts of the claim, anticipated indemnification and legal expenses and respective state rules. Claims are reviewed by us at least quarterly and an adjustment is made to the accrual based on the most current information.

S. Noncontrolling Interest. We maintain a controlling financial interest in certain of our less than wholly owned subsidiaries. We consolidate these subsidiaries as VIEs and present the third-party investors' portion of our net income (loss) and net assets as noncontrolling interest. Noncontrolling interest is included as a component of Members' Equity on the Consolidated Balance Sheets.

We fund a portion of our renewable generation assets through JVs with tax equity partners. We consolidate these JVs in accordance with ASC 810 as they are VIEs in which we hold a variable interest, and we control decisions that are significant to the JVs' ongoing operations and economic results (i.e., we are the primary beneficiary).

These JVs are subject to profit sharing arrangements in which the allocation of the JVs' cash distributions and tax benefits to members is based on factors other than members' relative ownership percentages. As such, we utilize the HLBV method to allocate proceeds to each partner at the balance sheet date based on the liquidation provisions of the related JV's operating agreement and adjust the amount of the VIE's net income attributable to us and the noncontrolling tax equity member during the period.

In each reporting period, the application of HLBV to our consolidated VIEs results in a difference between the amount of profit from the consolidated JVs and the amount included in regulated rates. As discussed above in "E. Basis of Accounting for Rate-Regulated Operations," we are subject to the accounting and reporting requirements of ASC 980. In accordance with these principles, we recognize a regulatory liability or asset for amounts representing the timing difference between the profit earned from the JVs and the amount included in regulated rates to recover our approved investments in consolidated JVs. The amounts recorded in income will ultimately reflect the amount allowed in regulated rates to recover our investments over the useful life of the projects. The offset to the regulatory liability or asset associated with our renewable investments included in regulated rates is recorded in "Depreciation expense" on the Statements of Consolidated Operations.

2. Recent Accounting Pronouncements

Recently Issued Accounting Pronouncements

In September 2025, the FASB issued ASU 2025-06, Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Targeted Improvements to the Accounting for Internal-Use Software. This pronouncement updates the guidance on capitalization of internal-use software, including removing the development stages utilized for evaluation of when certain activities are capital eligible. The ASU instead provides that an entity is required to start capitalizing eligible software development costs when (1) management has authorized and committed to funding the software project and (2) it is probable that the project will be completed and the software will be used to perform the function intended, which is referred to as the “probable-to-complete recognition threshold”. This probable-to-complete threshold includes an evaluation of whether there is significant uncertainty associated with the development activities of the software. The ASU is effective for fiscal years beginning after December 15, 2027. We are currently evaluating the impacts this amendment will have on our internal-use software capitalization policy.

Recently Adopted Accounting Pronouncements

In December 2023, the FASB issued ASU 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures. This pronouncement enhances required income tax disclosures. The pronouncement requires disclosure of specific categories and reconciling items included in the rate reconciliation, disaggregation between federal, state and local income taxes paid, and disclosure of income taxes paid by jurisdictions over a certain threshold. Additionally, the pronouncement eliminates certain required disclosures related to unrecognized tax benefits. We have adopted this ASU on a retrospective basis in the income tax footnote 15, for the year ended December 31, 2025.

3. Revenue Recognition

Customer Revenues. Substantially all of our revenues are tariff-based. Under ASC 606, the recipients of our utility service meet the definition of a customer, while the operating company tariffs represent an agreement that meets the definition of a contract, which creates enforceable rights and obligations. Our customers may participate in a program that allows for a fixed payment each month regardless of usage. Payments received that exceed the value of gas or electricity actually delivered are recorded as a liability and presented in "Customer deposits and credits" on the Consolidated Balance Sheets. Amounts in this account are reduced and revenue is recorded when customer usage exceeds payments received.

We have identified our performance obligations created under tariff-based sales as 1) the commodity (natural gas or electricity, which includes generation and capacity) and 2) delivery. These commodities are sold and/or delivered to and generally consumed by customers simultaneously, leading to satisfaction of our performance obligations over time as gas or electricity is delivered to customers. Due to the at-will nature of utility customers, performance obligations are limited to the services requested and received to date. Once complete, we generally maintain no additional performance obligations.

Transaction prices for each performance obligation are generally prescribed by our respective tariff. Rates include provisions to adjust billings for fluctuations in fuel and purchased power costs and cost of natural gas. Revenues are adjusted for differences between actual costs, subject to reconciliation, and the amounts billed in current rates. Under or over recovered revenues related to these cost recovery mechanisms are included in "Regulatory assets" or "Regulatory liabilities" on the Consolidated Balance Sheets and are recovered from or returned to customers through adjustments to tariff rates. As we provide and deliver service to customers, revenue is recognized based on the transaction price allocated to each performance obligation. Distribution revenues are generally considered daily or "at-will" contracts as customers may cancel their service at any time (subject to notification requirements), and revenue generally represents the amount we are entitled to bill customers.

In addition to tariff-based sales, NIPSCO Gas enters into balancing and exchange arrangements of natural gas as part of our operations and off-system sales programs. Performance obligations for these types of sales include transportation and storage of natural gas and can be satisfied at a point in time or over a period of time, depending on the specific transaction. For those transactions that span a period of time, we record a receivable or payable for any cumulative gas imbalances, as well as for any gas inventory borrowed or lent under a NIPSCO Gas exchange agreement.

Revenue Disaggregation and Reconciliation. We disaggregate revenue from contracts with customers based upon revenue pertaining to NIPSCO Gas, NIPSCO Electric, as well as by customer class.

Other Revenues. As permitted by accounting principles generally accepted in the United States, regulated utilities have the ability to earn certain types of revenue that are outside the scope of ASC 606. These revenues primarily represent revenue earned under alternative revenue programs. Alternative revenue programs represent regulator-approved mechanisms that allow for the adjustment of billings and revenue for certain approved programs. We maintain a variety of these programs, including demand side management initiatives that recover costs associated with the implementation of energy efficiency programs, as well as normalization programs that adjust revenues for the effects of weather or other external factors. Additionally, we maintain certain programs with future test periods that operate similarly to FERC formula rate programs and allow for recovery of costs incurred to replace aging infrastructure. When the criteria to recognize alternative revenue have been met, we establish a regulatory asset and present revenue from alternative revenue programs on the Statements of Consolidated Operations as “Other revenues”. When amounts previously recognized under alternative revenue accounting guidance are billed, we reduce the regulatory asset and record a customer account receivable.

The tables below reconcile revenue disaggregation by customer class to revenue pertaining to NIPSCO Gas and NIPSCO Electric, as well as to revenues reflected on the Statements of Consolidated Operations.

Year Ended December 31, 2025 *(in millions)*	NIPSCO Gas	NIPSCO Electric	Total
Customer Revenues			
Residential	$ 708.0	$ 768.4	$ 1,476.4
Commercial	270.0	713.9	983.9
Industrial	100.2	578.3	678.5
Wholesale	—	45.1	45.1
Public Authority	—	9.5	9.5
Miscellaneous [(1)]	13.5	(12.8)	0.7
Total Customer Revenues	$ 1,091.7	$ 2,102.4	$ 3,194.1
Other Revenues [(2)]	7.9	102.6	110.5
Total Operating Revenues	$ 1,099.6	$ 2,205.0	$ 3,304.6

(1) Amounts included in NIPSCO Gas Miscellaneous are primarily related to earnings sharing mechanisms and late fees. Amounts included in NIPSCO Electric Miscellaneous are primarily related to revenue trackers, public repairs, and property rentals offset by tracker deferrals and energy efficiency program deferrals.
(2) Amounts included in Other Revenues primarily relate to weather normalization adjustment mechanisms, MISO multi-value projects, and revenue from non-jurisdictional transmission assets.

Year Ended December 31, 2024 *(in millions)*	NIPSCO Gas	NIPSCO Electric	Total
Customer Revenues			
Residential	$ 531.4	$ 649.9	$ 1,181.3
Commercial	199.2	620.4	819.6
Industrial	79.0	499.1	578.1
Wholesale	—	38.3	38.3
Public Authority	—	8.1	8.1
Miscellaneous [(1)]	15.4	13.7	29.1
Total Customer Revenues	$ 825.0	$ 1,829.5	$ 2,654.5
Other Revenues [(2)]	13.4	84.1	97.5
Total Operating Revenues	$ 838.4	$ 1,913.6	$ 2,752.0

(1) Amounts included in NIPSCO Gas Miscellaneous are primarily related to earnings sharing mechanisms and late fees. Amounts included in NIPSCO Electric Miscellaneous are primarily related to revenue trackers, public repairs and property rentals.
(2) Amounts included in Other Revenues primarily relate to weather normalization adjustment mechanisms, MISO multi-value projects and revenue from non-jurisdictional transmission assets

Year Ended December 31, 2023 *(in millions)*	NIPSCO Gas	NIPSCO Electric	Total
Customer Revenues			
Residential	$ 634.9	$ 583.9	$ 1,218.8
Commercial	249.0	578.1	827.1
Industrial	86.9	474.1	561.0
Wholesale	—	32.0	32.0
Public Authority	—	11.5	11.5
Miscellaneous [(1)]	15.0	22.2	37.2
Total Customer Revenues	$ 985.8	$ 1,701.8	$ 2,687.6
Other Revenues [(2)]	0.8	83.2	84.0
Total Operating Revenues	$ 986.6	$ 1,785.0	$ 2,771.6

(1) Amounts included in NIPSCO Gas Miscellaneous are primarily related to earnings share mechanisms and late fees. Amounts included in NIPSCO Electric Miscellaneous are primarily related to revenue trackers, late fees and property rentals.
(2) Amounts included in NIPSCO Electric Other Revenues primarily relate to MISO multi-value projects and revenue from non-jurisdictional transmission assets.

Customer Accounts Receivable. Accounts receivable on our Consolidated Balance Sheets includes both billed and unbilled amounts, as well as certain amounts that are not related to customer revenues such as non-jurisdictional MISO multi-value projects. Unbilled amounts of accounts receivable relate to a portion of a customer's consumption of gas or electricity from the date of their last cycle billing through the last day of the month (balance sheet date). Factors taken into consideration when estimating unbilled revenue include historical usage, customer rates, and weather. A significant portion of our operations are subject to seasonal fluctuations in sales. During the heating season, primarily from November through March, revenues and receivables from gas sales are more significant than in other months. The opening and closing balances of customer receivables for the year ended December 31, 2025 are presented in the table below. We had no significant contract assets or liabilities during the period. Additionally, we have not incurred any significant costs to obtain or fulfill contracts.

(in millions)	Customer Accounts Receivable, Billed (less reserve)	Customer Accounts Receivable, Unbilled (less reserve)
Balance as of December 31, 2024	$ 188.2	$ 177.7
Balance as of December 31, 2025	294.1	201.3

Utility revenues are billed to customers monthly on a cycle basis. We expect that substantially all customer accounts receivable will be collected following customer billing, as this revenue consists primarily of periodic, tariff-based billings for service and usage. We maintain common utility credit risk mitigation practices, including requiring deposits and actively pursuing collection of past due amounts. We also utilize certain regulatory mechanisms that facilitate recovery of bad debt costs within tariff-based rates, which provides further evidence of collectability. It is probable that substantially all of the consideration to which we are entitled from customers will be collected upon satisfaction of performance obligations.

Allowance for Credit Losses. To evaluate for expected credit losses, customer account receivables are pooled based on similar risk characteristics, such as customer type, geography, payment terms, and related macro-economic risks. Expected credit losses are established using a model that considers historical collections experience, current information, and reasonable and supportable forecasts. Internal and external inputs are used in our credit model including, but not limited to, revenue projections, actual charge-offs data, recoveries data, shut-offs, security deposits, and final bill data. We continuously evaluate available information relevant to assessing collectability of current and future receivables. We evaluate creditworthiness of specific customers periodically or following changes in facts and circumstances. When we become aware of a specific commercial or industrial customer's inability to pay, an allowance for expected credit losses is recorded for the relevant amount. We also monitor other circumstances that could affect our overall expected credit losses including, but not limited to, creditworthiness of overall population in service territories, adverse conditions impacting an industry sector, and current economic conditions. Bad debt expense for the year ended December 31, 2025 was $13.2 million higher than the prior year primarily due to increases in aged receivables and anticipated higher delinquencies following colder weather in the fourth quarter.

At each reporting period, we record expected credit losses to an allowance for credit losses account. When deemed to be uncollectible, customer accounts are written-off. A rollforward of our allowance for credit losses as of December 31, 2025 and December 31, 2024 are presented in the tables below.

(in millions)		Total
Balance as of January 1, 2025	$	13.9
Current period provisions		26.2
Write-offs charged against allowance		(15.0)
Recoveries of amounts previously written off		1.1
Balance as of December 31, 2025	$	26.2

(in millions)		Total
Balance as of January 1, 2024	$	11.9
Current period provisions		12.1
Write-offs charged against allowance		(11.0)
Recoveries of amounts previously written off		0.9
Balance as of December 31, 2024	$	13.9

4. Noncontrolling Interest

Variable Interest Entities. A VIE is an entity in which the controlling interest is determined through means other than a majority voting interest. Refer to Note 1, "Nature of Operations and Summary of Significant Accounting Policies - S. Noncontrolling Interest," for information on our accounting policy for the VIEs.

We own and operate two wind facilities, Rosewater and Indiana Crossroads Wind, which have 102 MW and 302 MW of nameplate capacity, respectively. We also own and operate two solar facilities, Indiana Crossroads Solar and Dunns Bridge I, which have 200 MW and 265 MW of nameplate capacity, respectively. We have determined that these JVs are VIEs. We control decisions that are significant to these entities' ongoing operations and economic results. Therefore, we have concluded that we are the primary beneficiary and have consolidated all four entities.

Members of each respective JV include NIPSCO (who is the managing member) and a tax equity partner. Earnings, tax attributes and cash flows are allocated to both us and the tax equity partner in varying percentages by category and over the life of the partnership. We, along with each tax equity partner, contributed cash to the respective JV. Once the tax equity partner has earned their negotiated rate of return and the JV has reached a stated contractual date, we have the option to purchase the remaining interest in the respective JV from the tax equity partner. We have an obligation to purchase 100% of the electricity generated by each commercially operational JV.

We did not provide any financial or other support for the JVs during the year that was not contractually required.

Our Consolidated Balance Sheets included the following assets and liabilities associated with the JV VIEs.

At December 31, *(in millions)*		**2025**		2024
Net property, plant and equipment	**$**	**1,273.0**	$	1,323.8
Current assets		**27.6**		65.0
Total Assets [(1)]	**$**	**1,300.6**	$	1,388.8
Current liabilities	**$**	**16.1**	$	53.7
Asset retirement obligations		**55.7**		58.3
Finance lease obligations	**$**	**40.1**	$	40.4
Total Liabilities [(1)(2)]	**$**	**111.9**	$	152.4

(1) The assets of each VIE represent assets of a consolidated VIE that can be used only to settle obligations of the respective consolidated VIE. The creditors of the liabilities of the VIEs do not have recourse to the general credit of the primary beneficiary.
(2) In addition to the amounts disclosed above, there is a de minimis amount of other noncurrent assets and liabilities at Rosewater as of December, 31, 2025.

GenCo. GenCo will acquire and build generation assets and provide capacity and electricity to support data center customers through a PPA with NIPSCO. It was determined NIPSCO has a variable interest in GenCo through the PPA, but is not the primary beneficiary of GenCo because NIPSCO does not have the power to direct the significant decision-making activities that most impact the ongoing operations and economic performance of GenCo. As such, NIPSCO does not consolidate GenCo, with no amount of NIPSCO's consolidated balance sheet related to GenCo. NIPSCO is not exposed to losses due to the PPA. The PPA includes termination provisions that provide GenCo with recovery of its Generation Assets. Generation Holdings II and its wholly owned subsidiary, GenCo, is a consolidated VIE of NiSource, and is a related party to NIPSCO.

5. Equity

Noncontrolling Interest in Consolidated Subsidiaries. As of December 31, 2025 and 2024, NIPSCO and tax equity partners have completed their cash contributions into the Indiana Crossroads Wind, Rosewater, Indiana Crossroads Solar and Dunns Bridge I JVs. Earnings, tax attributes and cash flows are allocated to both NIPSCO and the respective tax equity partners in varying percentages by category and over the life of the partnership. The tax equity partner's contributions, net of these allocations, is represented as a noncontrolling interest within Members' Equity on the Consolidated Balance Sheets. Refer to Note 4, "Noncontrolling Interest," for more information.

6. Short-Term Borrowings

NiSource Intercompany Revolving Credit Agreement. On December 27, 2023, NIPSCO and NARC entered into Intercompany Revolving Credit Agreements with NiSource (NiSource IRCA). These are lending agreements only and there will be no deposits related to the agreements.

We satisfy our liquidity requirements primarily through internally generated funds and through intercompany borrowings from NiSource via the NiSource IRCA. NIPSCO may borrow a maximum of $1.0 billion through the NiSource IRCA as approved by the FERC. As of December 31, 2025, NIPSCO had $485.2 million of short-term NiSource IRCA borrowings outstanding at an interest rate of 4.06%. As of December 31, 2024, NIPSCO had $41.9 million of short-term NiSource IRCA borrowings outstanding at an interest rate of 4.79%. NARC may borrow a maximum of $325.0 million through the NiSource IRCA. As of December 31, 2025, NARC had $214.2 million of short-term NiSource IRCA borrowings outstanding at an interest rate of 4.06%. As of December 31, 2024, NARC had $200.4 million of short-term NiSource IRCA borrowings outstanding at an interest rate of 4.79%. Amounts received from the NiSource IRCA are reflected in "Short-term borrowings - affiliated" on the Consolidated Balance Sheets.

Accounts Receivable Transfer Program. We maintain a receivables agreement whereby we transfer customer accounts receivables to a third party financial institution through our wholly owned and consolidated special purpose entity, NARC. The current agreement expires on August 13, 2026 and may be further extended if mutually agreed to by the parties thereto.

All receivables transferred to a third party are valued at face value, which approximates fair value due to their short-term nature. The amount of the undivided percentage ownership interest in the accounts receivables transferred is determined in part by required loss reserves under the agreement.
Transfers of accounts receivable are accounted for as secured borrowings resulting in the recognition of short-term borrowings on the Consolidated Balance Sheets. As of December 31, 2025, the maximum amount of debt that could be recognized related to our accounts receivable program is $100.0 million.

We had no short-term borrowings related to the securitization transactions as of December 31, 2025 and December 31, 2024, respectively.

For the year ended December 31, 2025, there were no cash flows used for financing activities recorded related to the change in short-term borrowings due to securitization transactions. For the year ended December 31, 2024, $157.6 million was recorded as cash flows used for financing activities related to the change in short-term borrowings due to securitization transactions. For the accounts receivable transfer program, we pay used facility fees for amounts borrowed, unused commitment fees for amounts not borrowed and upfront renewal fees. Fees associated with the securitization transactions were $0.8 million, $0.7 million and $1.3 million for the years ended December 31, 2025, 2024 and 2023, respectively. We remain responsible for collecting on the receivables securitized, and the receivables cannot be transferred to another party. Refer to Note 19, "Interest Expense, Net" for additional information on securitization transaction fees.

Items listed above, with the exception of the NiSource IRCA, are presented net in the Statements of Consolidated Cash Flows as their maturities are less than 90 days.

7. Long-Term Debt

Our long-term debt as of December 31, 2025 and 2024 is as follows.

As of December 31, (in millions)	2025	2024
Medium-Term Notes —		
7.69% due June 6, 2027	**20.0**	20.0
7.69% due June 27, 2027	**33.0**	33.0
7.16% due August 4, 2027	**5.0**	5.0
Total Medium-Term Notes	**58.0**	58.0
Affiliated Notes —		
5.99% due September 18, 2025	**—**	75.0
6.41% due December 4, 2029	**120.0**	120.0
4.55% due June 26, 2035	**93.8**	93.8
4.53% due December 21, 2037	**55.0**	55.0
5.17% due July 26, 2038	**89.0**	89.0
4.83% due December 19, 2042	**95.0**	95.0
5.43% due July 24, 2043	**95.0**	95.0
4.99% due February 15, 2044	**66.0**	66.0
4.35% due December 16, 2044	**82.0**	82.0
4.99% due June 26, 2045	**93.7**	93.7
4.70% due December 30, 2045	**91.0**	91.0
4.36% due December 30, 2046	**210.0**	210.0
4.16% due June 30, 2047	**40.0**	40.0
4.11% due September 29, 2047	**162.5**	162.5
4.53% due June 29, 2048	**450.0**	450.0
3.57% due September 30, 2049	**150.0**	150.0
3.17% due June 30, 2050	**208.0**	208.0
3.27% due June 30, 2051	**175.0**	175.0
5.08% due June 30, 2052	**225.0**	225.0
5.65% due December 30, 2052	**210.0**	210.0
5.32% due March 31, 2053	**250.0**	250.0
5.30% due April 28, 2053	**315.0**	315.0
5.43% due December 15, 2053	**300.0**	300.0
5.67% due March 28, 2054	**175.0**	175.0
5.91% due June 28, 2054	**250.0**	250.0
5.38% due September 30, 2054	**100.0**	100.0
5.92% due December 31, 2054	**200.0**	200.0
5.84% due March 31, 2055	**525.0**	—
5.90% due June 30, 2055	**100.0**	—
5.71% due September 30, 2055	**100.0**	—
5.82% due December 31, 2055	**50.0**	—
Total Affiliated Notes	5,076.0	4,376.0
Total Finance Leases (maturity from December 2027 to November 2035)	**165.4**	**124.2**
Unamortized Discounts	**—**	—
Less: Current portion of long-term debt	**(8.6)**	(81.8)
Total Long-Term Debt	**$ 5,290.8**	$ 4,476.4

Details of our 2025 long-term debt related activity are summarized below.

- On March 31, 2025, we issued $525.0 million of 5.84% intercompany notes.
- On June 30, 2025 we issued $100.0 million of 5.90% intercompany notes.
- On September 30, 2025 we issued $100.0 million of 5.71% intercompany notes.
- On December 31, 2025, we issued $50.0 million of 5.82% intercompany notes.

Details of our 2024 long-term debt related activity are summarized below.

- On March 28, 2024, we issued $175.0 million of 5.67% intercompany notes.
- On June 28, 2024, we issued $250.0 million of 5.91% intercompany notes.
- On September 30, 2024, we issued $100.0 million of 5.38% intercompany notes
- On December 31, 2024, we issued $200.0 million of 5.92% intercompany notes.

See Note 17, "A. Contractual Obligations," for the outstanding long-term debt maturities at December 31, 2025.

Unamortized discount on long-term debt applicable to outstanding bonds are being amortized over the lives of such bonds.

8. Property, Plant and Equipment

Our property, plant and equipment on the Consolidated Balance Sheets were classified as follows..

At December 31, *(in millions)*	2025	2024
Property Plant and Equipment		
Gas Distribution Utility	**$ 5,454.9**	$ 5,180.6
Electric Utility	**11,420.7**	8,666.8
Construction Work in Process	**1,240.7**	1,630.8
JV Renewable Generation Assets (1)	**1,429.3**	1,434.2
Non-Utility and Other	**1,710.5**	1,662.2
Total Property Plant and Equipment	**$ 21,256.1**	$ 18,574.6
Accumulated Depreciation and Amortization		
Gas Distribution Utility	**(1,425.9)**	(1,396.2)
Electric Utility	**(2,987.0)**	(2,707.8)
JV Renewable Generation Assets (1)	**(156.3)**	(110.4)
Non-Utility and Other	**(1,615.4)**	(1,523.5)
Total Accumulated Depreciation and Amortization	**$ (6,184.6)**	$ (5,737.9)
Net Property, Plant and Equipment	**$ 15,071.5**	$ 12,836.7

(1) Our JV renewable generation assets represent Non-Utility Property owned and operated by JVs between us and unrelated tax equity partners and depreciated straight-line over 30 years. Refer to Note 4, "Noncontrolling Interest," for additional information.

The weighted average depreciation provisions for utility plant, as a percentage of the original cost, for the periods ended December 31, 2025, 2024 and 2023 were as follows.

	2025	2024	2023
NIPSCO Electric	**3.5%**	3.5%	3.5%
NIPSCO Gas	**2.3%**	1.9%	1.9%

We recognized depreciation expense of $526.1 million, $431.6 million and $386.7 million for the years ended 2025, 2024 and 2023, respectively. The 2025, 2024 and 2023 depreciation expense also includes $62.4 million, $58.9 million and $12.5 million related to the regulatory deferral of income associated with our JVs, which is not included in current rates. See Note 1, "Nature of Operations and Summary of Significant Accounting Policies - S. Noncontrolling Interest," for additional information.

Amortization of on-premise Software Costs. We amortized $27.5 million, $39.8 million and $35.8 million in 2025, 2024 and 2023, respectively, related to software recorded as intangible assets. Our unamortized software balance was $213.3 million and $142.6 million at December 31, 2025 and 2024, respectively.

Amortization of Cloud Computing Costs. We amortized $13.9 million, $9.6 million and $5.3 million in 2025, 2024 and 2023, respectively, related to cloud computing costs to "Operation and maintenance" expense. Our unamortized cloud computing balance was $77.7 million and $55.6 million at December 31, 2025 and 2024, respectively.

9. Goodwill

Our goodwill assets as of December 31, 2025 and 2024 were $17.8 million and relate to the purchase of Kokomo Gas in February 1992 and Northern Indiana Fuel and Light in March 1993.

For our annual goodwill impairment analysis performed as of May 1, 2025, we performed a qualitative "step 0" assessment and determined that it was more likely than not that the estimated fair value of NIPSCO Gas substantially exceeded its carrying value. For this test, we assessed various assumptions, events, and circumstances that would have affected the estimated fair value of NIPSCO Gas as compared to our baseline May 1, 2024 "step 1" fair value measurement. There have been no impairments recorded during the periods presented.

10. Asset Retirement Obligations

We have recognized asset retirement obligations associated with various legal obligations, including costs to remove and dispose of certain construction materials located within many of our facilities (including our JV facilities), certain costs to retire pipeline, removal costs for certain underground storage tanks, closure costs for certain sites including ash ponds, solid waste management units and a landfill, as well as some other nominal asset retirement obligations. We also have an obligation associated with the decommissioning of our two hydro facilities located in Indiana. These hydro facilities have an indeterminate life, and as such, no asset retirement obligation has been recorded.

During 2025, we continued to evaluate the applicability of revisions to the EPA rule for disposal of CCRs, which was announced in May 2024. As a result, during 2025, we recorded an increase of $48.9 million based on initial assessments of estimated costs to comply with the EPA rule for certain sites. Additional costs will be recorded if they become probable and estimable. These costs are expected to be recoverable through existing and future depreciation rates. See Note 17, "Other Commitments and Contingencies - D. Environmental Matters," for additional information on the legacy CCR rule.

Changes in our liability for asset retirement obligations for the years 2025 and 2024 are presented in the table below.

(in millions)		**2025**		2024
Beginning Balance	**$**	**691.7**	$	466.0
Accretion recorded as a regulatory asset/liability		**39.9**		20.7
Additions		**63.3**		189.9
Settlements		**(73.0)**		(72.5)
Change in estimated cash flows		**18.6**		87.6
Ending Balance	**$**	**740.5**	$	691.7

Certain non-legal costs of removal not yet incurred but have been, and continue to be, included in depreciation rates and collected in our customer rates are classified as “Regulatory liabilities” on the Consolidated Balance Sheets.

11. Regulatory Matters
Regulatory Filings

Renewable generation filings. In February 2025, we filed a petition with the IURC to modify our February 2023 order that approved a power purchase agreement related to Templeton and allow for us to fully own Templeton. The IURC issued an order in September 2025 approving the filed petition.

NIPSCO Electric rate case filing. In February 2025, we and certain intervening parties filed a Joint Stipulation and Settlement Agreement with the IURC. The IURC issued an order in June 2025, approving the Settlement Agreement without modification. New rates were implemented in multiple steps beginning in July 2025 with the final step implemented in March 2026.

GenCo filing. In January 2025, GenCo, an indirect subsidiary of NiSource Inc., filed a declination of jurisdiction petition with the IURC related to the ownership, development, financing, construction and operation of generation facilities. This was an administrative filing and is a step in our effort to set up a framework to accommodate megaload customers, including data centers. A settlement agreement between us, GenCo, and a coalition of our largest industrial customers was approved by the IURC in September 2025. In October 2025, the Indiana Office of the Utility Consumer Counselor ("OUCC") filed a limited Request for Rehearing with the IURC and the OUCC filed a Notice of Appeal of the IURC order approving the GenCo settlement, which was immediately stayed by the Court of Appeals to allow the IURC process to be completed. In November 2025, the IURC issued an order granting the OUCC’s limited request for rehearing, which was supported by us and GenCo. In December 2025, all parties who originally appealed the IURC approval filed motions to dismiss their respective appeals.

NIPSCO Electric Special Contract and GenCo PPA filing. In November 2025, we, along with GenCo, filed an application with the IURC seeking approval of (i) a retail special contract for electric service between NIPSCO and ADS, (ii) a related power purchase agreement between NIPSCO and GenCo, and (iii) an alternative regulatory plan and associated accounting treatment. Testimony from the OUCC and intervenors was filed in January 2026. On February 26, 2026, NIPSCO, GenCo, the OUCC, and the NIPSCO Industrial Group filed a Stipulation and Settlement Agreement ("Settlement") resolving all issues and accompanying testimony with the IURC. The Citizens Action Coalition ("CAC") has indicated it intends to oppose the Settlement, and the LaPorte County Board of Commissioners has indicated it intends to not oppose the Settlement. A settlement hearing is scheduled for April 7, 2026. An order is anticipated in the second quarter of 2026.

202(c) Emergency Order for R.M. Schahfer coal facility. In December 2025, before the planned retirement of the R.M. Schahfer coal facility, the U.S. Secretary of Energy issued an emergency order under section 202(c) of the Federal Power Act requiring R.M. Schahfer to continue operating for 90 days, through March 23, 2026. The order stated that continued operation of R.M. Schahfer was required to meet an energy emergency across MISO’s North and Central regions. Following receipt of the emergency order, we filed a complaint at FERC seeking a modification of the MISO Tariff to establish a mechanism for recovery and allocation of the cost to comply with this order. In March 2026, FERC granted the complaint. We made two filings with the IURC related to the emergency order. The first filing is to confirm accounting treatment of the current electric rate order, and the second is a filing for recovery of federally mandated expenses related to the emergency order, which will be utilized in the event that any costs of complying with the emergency order fall outside of the MISO Tariff recovery. The Michigan City coal facility is scheduled to be retired by the end of 2028.

IURC Investigation. In November 2025, the IURC initiated an investigation into the accuracy of our gas meters. This investigation followed our disclosure of a latent issue with a small percentage of the meter indexes in our gas meters, which was discovered during roll-out of new AMI communications modules for gas meters. A procedural schedule has been established and a hearing is expected in July 2026.

Regulatory Assets and Liabilities
We follow the accounting and reporting requirements of ASC Topic 980, which provides that regulated entities account for and report assets and liabilities consistent with the economic effect of regulatory rate-making procedures when the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates will be charged and collected from customers. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income or expense are deferred on the balance sheet and are recognized in the income statement as the related amounts are included in customer rates and recovered from or refunded to customers. We assess the probability of collection for all of our regulatory assets each period. The offset to the regulatory liability associated with our renewable investments included in regulated rates is recorded in "Depreciation and amortization" on the Statements of Consolidated Operations.

Regulatory assets were comprised of the following items.

At December 31, *(in millions)*		**2025**		2024
Regulatory Assets				
Unrecognized pension and other postretirement benefit costs (see Note 15)	**$**	**341.0**	$	378.5
Environmental costs (see Note 17-D.)		**20.5**		15.1
Under-recovered gas and fuel costs (see Note 1-I.)		**13.5**		4.2
Depreciation		**18.8**		23.7
Post-in-service carrying charges		**11.0**		13.7
DSM programs		**2.0**		—
Retired coal generating stations		**552.1**		617.0
Losses on commodity price risk programs (see Note 12)		**9.4**		5.4
Renewable energy investments (See Note 1-S. and Note 4)		**130.7**		81.3
WAM system filing		**33.5**		21.5
Uncollected future cost of removal		**102.5**		—
Other		**35.2**		35.6
Total Regulatory Assets	**$**	**1,270.2**	**$**	**1,196.0**
Less: Current Portion		**141.1**		**127.2**
Total Noncurrent Regulatory Assets	**$**	**1,129.1**	**$**	**1,068.8**

Regulatory liabilities were comprised of the following items.

At December 31, *(in millions)*		**2025**		2024
Regulatory Liabilities				
Over-recovered gas and fuel costs (see Note 1-I.)	**$**	**27.3**	$	6.1
Cost of removal (see Note 10)		**—**		45.8
Gains on commodity price risk programs (see Note 12)		**17.4**		26.2
Customer assistance programs		**1.5**		—
DSM programs		**19.9**		18.0
Renewable energy investments		**139.4**		77.0
Other		**17.7**		4.5
Total Regulatory Liabilities	**$**	**223.2**	**$**	**177.6**
Less: Current Portion		**148.3**		37.2
Total Noncurrent Regulatory Liabilities	**$**	**74.9**	$	140.4

Regulatory assets, including under-recovered gas and fuel costs and depreciation, of approximately $78.0 million and $70.0 million as of December 31, 2025 and 2024, respectively, are not earning a return on investment. These costs are recovered over a remaining life between 15 and 70 years.

Assets:
Unrecognized pension and other postretirement benefit costs. Represents the deferred other comprehensive income or loss of the actuarial gains or losses and the prior service costs or credits that arise during the period but that are not immediately recognized as components of net periodic benefit costs that will ultimately be recovered through base rates.

Environmental costs. Includes certain recoverable costs related to gas plant sites, disposal sites or other sites onto which material may have migrated. The recovery of these costs is to be addressed in future base rates, billing riders, or tracking mechanisms.

Under-recovered gas and fuel costs. Represents the difference between the costs of gas and fuel, as well as energy acquired through power purchase agreements, including our own renewable projects, and the recovery of such costs in revenue and is

used to adjust future billings for such deferrals on a basis consistent with IURC-approved tariff provisions. Recovery of these costs is achieved through tracking mechanisms.

Depreciation. Represents differences between depreciation expense incurred on a GAAP basis and that prescribed through regulatory order. Significant components of this balance include:

- **TDSIC.** We obtained approval from the IURC to recover costs for certain system modernization projects outside of a base rate proceeding. Eighty percent of the related costs, including depreciation, property taxes and debt and equity based carrying charges (see *Post-in-service carrying charges* below) are recovered through a semi-annual recovery mechanism. Recovery of these costs will continue through the TDSIC tracker until such assets are included in rate base through a gas or electric base rate case, respectively. The remaining twenty percent of the costs are deferred until the next base rate case. As of December 31, 2025 and 2024, depreciation of $13.1 million and $23.7 million, respectively, was deferred as a regulatory asset.

Post-in-service carrying charges. Represents deferred debt-based carrying charges incurred on certain assets placed into service but not yet included in customer rates. Deferral of equity-based carrying charges for the TDSIC program is allowed, however, such amounts are not reflected in regulatory asset balances for financial reporting as equity-based returns do not meet the definition of incurred costs under ASC 980. See description of TDSIC program above under the heading “Depreciation.”

DSM programs. Represents costs associated with our energy efficiency and conservation programs. Costs are recovered through tracking mechanisms.

Retired coal generating stations. Represents the net book value of Units 7 and 8 of Bailly Generating Station that was retired during 2018 and the net book value of Units 14 and 15 of R.M. Schahfer Generating Station retired in 2021. These amounts are currently being amortized at a rate consistent with their inclusion in customer rates. The August 2023 NIPSCO Electric rate case order extends the recovery of, and on, the net book value of the stations by the end of 2034 and implements a revenue credit for the retired units. The credit is based on the difference between the year-end value of Units 14 and 15 and the most recent value established in the last base rate case proceeding or credit compliance filing.

Losses on commodity price risk programs. Represents the unrealized losses related to our commodity price risk programs. These programs help to protect against the volatility of commodity prices and these amounts are collected from customers through their inclusion in customer rates.

Renewable energy investments. Represents the regulatory deferral of renewable energy formation and developer costs primarily through deferred depreciation.

WAM system filing. Represents the deferral of certain costs, including depreciation and amortization incurred in connection with improvements to its information technology systems through the design, development, and implementation of a new WAM program for the scheduling, dispatch, and execution of work and the management of underlying assets.
Uncollected future cost of removal. Represents asset removal costs not yet recovered.

Liabilities:

Over-recovered gas and fuel costs. Represents the difference between the cost of gas and fuel, as well as energy acquired through power purchase agreements, including our own renewable projects and, the recovery of such costs in revenues and is the basis to adjust future billings for such refunds on a basis consistent with IURC-approved tariff provisions. Refunding of these revenues is achieved through tracking mechanisms.

Cost of removal. Represents anticipated costs of removal for utility assets that have been collected through depreciation rates for future costs to be incurred.

Gains on commodity price risk programs. Represents the unrealized gains related to our commodity price risk programs. These programs help to protect against the volatility of commodity prices, and these amounts are passed back to customers through their inclusion in customer rates.

Customer assistance programs. Represents the difference between the eligible customer assistance program costs and collections, which will be refunded to customers.

DSM programs. Represents costs associated with our energy efficiency and conservation programs. Costs are recovered through tracking mechanisms.

Renewable energy investments. Represents the regulatory deferral of certain amounts representing the timing difference between the profit earned from the JVs and the amount included in regulated rates to recover our approved investments in consolidated JVs. The offset to the regulatory liability associated with our renewable investments is recorded in "Depreciation expense" on the Statements of Consolidated Operations. Refer to Note 1, "Nature of Operations and Summary of Significant Accounting Policies - S. Noncontrolling Interest," Note 4, "Noncontrolling Interest," and Note 8, "Property, Plant and Equipment," for additional information.

12. Risk Management Activities

We are exposed to certain risks related to our ongoing business operations; namely commodity price risk. We recognize that the prudent and selective use of derivatives may help to limit volatility in the price of natural gas.

Risk management assets and liabilities associated with our derivatives are presented on the Consolidated Balance Sheets as shown below.

	December 31, 2025		**December 31, 2024**	
(in millions)	**Assets**	**Liabilities**	**Assets**	**Liabilities**
Current Derivatives not designated as hedging instruments [1]	**$ 8.1**	**$ 1.4**	$ 9.1	$ 2.3
Noncurrent Derivatives not designated as hedging instruments [2]	**$ 8.8**	**$ 3.7**	$ 17.9	$ 1.2

[1] Presented in "Prepayments and other" and "Other accruals", respectively, on the Consolidated Balance Sheets.
[2] Presented in "Deferred charges and other" and "Other noncurrent liabilities and deferred credits" on the Consolidated Balance Sheets.

Our derivative instruments are subject to enforceable master netting arrangements or similar agreements. No collateral was either received or posted related to our outstanding derivative positions at December 31, 2025 and 2024. If the above gross asset and liability positions were presented net of amounts owed or receivable from counterparties, we would report a net asset position of $11.8 million and $23.5 million at December 31, 2025 and 2024, respectively.

Derivatives Not Designated as Hedging Instruments
Commodity Price Risk Management. We, along with our utility customers, are exposed to variability in cash flows associated with natural gas purchases and volatility in natural gas prices. We purchase natural gas for sale and delivery to our retail, commercial and industrial customers, and for most customers the variability in the market price of gas is passed through in their rates. We offer programs to certain customers whereby we assume the variability in the market price of gas. The objective of our commodity price risk programs is to mitigate the gas cost variability, for us or on behalf of our customers, associated with natural gas purchases or sales by economically hedging the various gas cost components using a combination of futures, options, forwards or other derivative contracts. As of December 31, 2025 and 2024, we had 83.7 MMDth and 77.8 MMDth, respectively, of net energy derivative volumes outstanding related to our natural gas hedges.

We received IURC approval to lock in a fixed price for our natural gas customers using long-term forward purchase instruments and is limited to 20% of our average annual GCA purchase volume. As of December 31, 2025, the remaining terms of these instruments range from one to three years.

All gains and losses on these derivative contracts are deferred as regulatory liabilities or assets and are remitted to or collected from customers through our quarterly GCA mechanism.

13. Fair Value

A. Fair Value Measurements.

Recurring Fair Value Measurements

The following tables present financial assets and liabilities measured and recorded at fair value on our Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2025 and December 31, 2024.

As of December 31, 2025 and December 31, 2024, there were no material transfers between fair value hierarchies. Additionally, there were no changes in the method or significant assumptions used to estimate the fair value of our risk management assets and liabilities.

Recurring Fair Value Measurements December 31, 2025 *(in millions)*	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2025
Risk Management Assets	**$ —**	**$ 16.9**	**$ —**	**$ 16.9**
Risk Management Liabilities	**$ —**	**$ 5.1**	**$ —**	**$ 5.1**

Recurring Fair Value Measurements December 31, 2024 *(in millions)*	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2024
Risk Management Assets	$ —	$ 27.0	$ —	$ 27.0
Risk Management Liabilities	$ —	$ 3.5	$ —	$ 3.5

Level 1 - When utilized, exchange-traded derivative contracts are based on unadjusted quoted prices in active markets and are classified within Level 1. These financial assets and liabilities are secured with cash on deposit with the exchange; therefore, nonperformance risk has not been incorporated into these valuations. These financial assets and liabilities are deemed to be cleared and settled daily by NYMEX as the related cash collateral is posted with the exchange. As a result of this exchange rule, NYMEX derivatives are considered to have no fair value at the balance sheet date for financial reporting purposes, and
are presented in Level 1 net of posted cash; however, the derivatives remain outstanding and are subject to future commodity price fluctuations until they are settled in accordance with their contractual terms.

Level 2 - Certain non-exchange-traded derivatives are valued using broker or over-the-counter, on-line exchanges. In such cases, these non-exchange-traded derivatives are classified within Level 2. Non-exchange-based derivative instruments include forwards and options. In certain instances, these instruments may utilize models to measure fair value. We use a similar model to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability and market-corroborated inputs, (i.e. inputs derived principally from or corroborated by observable market data by correlation or other means). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized within Level 2.

Level 3 - Certain derivatives trade in less active markets with a lower availability of pricing information and models may be utilized in the valuation. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized within Level 3.

Risk Management Assets and Liabilities. Risk management assets and liabilities include exchange-traded NYMEX futures and NYMEX options and non-exchange-based forward purchase contracts. We have entered into long-term forward natural gas purchase instruments to lock in a fixed price for natural gas customers. We value these contracts using a pricing model that incorporates market-based information when available, as these instruments trade less frequently and are classified within Level 2 of the fair value hierarchy. For additional information, see Note 12, "Risk Management Activities."

Non-recurring Fair Value Measurements

We measure the fair value of certain assets, including goodwill, on a non-recurring basis, typically when events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. As of December 31, 2025, no non-recurring fair value adjustments have been made.

B. Other Fair Value Disclosures for Financial Instruments. The carrying amount of cash and cash equivalents, restricted cash, customer deposits, and short-term borrowings is a reasonable estimate of fair value due to their liquid or short-term nature. Our long-term borrowings are recorded at historical amounts.

The following methods and assumptions were used to estimate the fair value of each class of financial instruments.

Long-term Debt. The fair value of outstanding long-term debt is estimated based on the quoted market prices for the same or similar securities. Certain premium costs associated with the early settlement of long-term debt are not taken into consideration in determining fair value. These fair value measurements are classified within Level 2 of the fair value hierarchy. For the years ended December 31, 2025 and 2024, there was no change in the method or significant assumptions used to estimate the fair value of long-term debt.

The carrying amount and estimated fair values of financial instruments were as follows.

	Carrying Amount	**Estimated Fair Value**	Carrying Amount	Estimated Fair Value
As of December 31, *(in millions)*	**2025**	**2025**	2024	2024
Long-term debt (including current portion)	**$ 5,299.4**	**$ 4,825.7**	$ 4,558.3	$ 4,072.4

14. Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws and associated regulations involves uncertainty, as taxing authorities may interpret the laws differently.
Our historical business activities through the closing of the Minority Interest Transaction in 2023 were included in the consolidated U.S. federal and certain state income tax returns of NiSource Inc. Prior to April 13, 2023, we were treated as a taxable division of our corporate parent, NiSource Inc. Beginning on that date, we became a division of NIPSCO Holdings I. In connection with the Minority Interest Transaction, except for NARC, NIPSCO Holdings I retained NIPSCO's income tax balances and 80.1% of the excess deferred income tax regulatory balances as described below.

Our financial statements reflect a provision for income taxes attributable to NARC through December 31, 2025. For income tax purposes, NIPSCO is a disregarded entity that is wholly owned by the NIPSCO Holdings II partnership, while NIPSCO Accounts Receivable Company ("NARC") is taxed as a corporation.

Income Tax Expense. The components of income tax expense (benefit) were as follows.

Year Ended December 31, *(in millions)*	2025	2024	2023
Income Taxes			
Current			
Federal	$ **2.2**	$ —	$ 32.1
State	**—**	—	6.2
Total Current	$ **2.2**	$ —	$ 38.3
Deferred			
Federal			
Taxes before operating loss carryforwards and investment tax	**3.5**	(3.0)	(8.9)
Tax utilization expense of operating loss carryforwards	**—**	—	21.3
Investment tax credits	**—**	—	(2.1)
State	**(0.9)**	(0.8)	13.9
Total Deferred	**2.6**	(3.8)	24.2
Deferred Investment Credits	**—**	—	(0.3)
Income Taxes	$ **4.8**	$ (3.8)	$ 62.2

In connection with the Minority Interest Transaction during 2023, NiSource recognized a $63.5 million income tax benefit in additional paid in capital related to 19.9% of our excess deferred income taxes attributable to Blackstone's noncontrolling interest. This benefit does not impact our regulatory books or the excess deferred taxes that will benefit customers through lower future rates in accordance with applicable regulatory orders.

Statutory Rate Reconciliation. The following table represents a reconciliation of income tax expense at the statutory federal income tax rate to the actual income tax expense from continuing operations.

Year Ended December 31, *(in millions)*	2025		2024		2023	
Book income before income taxes	$ **713.4**		$ 597.5		$ 401.1	
Tax expense at statutory federal income tax rate	**149.8**	**21.0%**	125.5	21.0%	84.2	21.0%
Increases (reductions) in taxes resulting from:						
State income taxes, net of federal income tax benefit	**(0.7)**	**(0.1)**	(0.8)	(0.1)	9.2	2.3
Regulatory treatment of depreciation differences	**—**	**—**	—	—	(28.0)	(7.0)
NIPSCO pass-through income	**(152.7)**	**(21.5)**	(128.5)	(21.5)		
AFUDC equity					(4.8)	(1.2)
Changes in Valuation Allowance	**8.4**	**1.1**	—	—	—	—
Other adjustments					1.6	0.4
Income Taxes	$ **4.8**	**0.7%**	$ (3.8)	**(0.6)%**	$ 62.2	15.5%

For the year ended December 31, 2025, the state and local income tax reconciling item represents the tax effect of income in Indiana, which accounted for more than 50 percent of the company's state and local tax liability.

The increase in income tax expense in 2025 vs 2024 is primarily attributed to the establishment of a valuation allowance on deferred tax assets related to disallowed §163(j) interest carryforwards.

The decrease in income tax expense in 2024 vs 2023 is primarily attributed to the adjustment for NIPSCO's passthrough income and pre-tax loss from NARC.

Cash Taxes Paid Disclosure. The following table provides cash taxes paid for each period presented, which represents the actual cash payments made for income taxes to federal authorities and differs from the income tax expense recognized for financial reporting purposes due to deferred taxes, credits, and other reconciling items.

At December 31, *(in millions)*	2025	2024	2023
Jurisdiction			
Federal	$ **2.5**	$ —	$ —
Total Cash Taxes Paid	$ **2.5**	$ —	$ —

Deferred Income Tax Assets Components. Deferred income taxes result from temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. In connection with the Minority Interest Transaction, NIPSCO's deferred taxes were removed from our GAAP books and were reconstituted as deferred taxes on the outside basis difference of NiSource's investment in the NIPSCO Holdings II partnership.

At December 31, *(in millions)*	2025	2024
Deferred Tax Assets		
Net operating loss carryforward	$ **1.3**	$ 3.8
Disallowed §163(j) interest expense carryforward	$ **8.4**	$ —
Total Deferred Tax Assets	$ **9.7**	$ 3.8
Valuation Allowance	$ **(8.4)**	$ —
Net Deferred Tax Assets	$ **1.3**	$ 3.8

Deferred tax assets include amounts for disallowed §163(j) interest expense carryforward; during the period, we recorded a valuation allowance on these amounts in accordance with realizability requirements, and corresponds to the unfavorable item presented in the rate reconciliation. We believe it is not more likely than not that the Federal §163(j) disallowed interest expense carryforward will be realized. We have recorded a valuation allowance of $8.4 million on the deferred tax asset related to the Federal §163(j) interest expense carryforward.

NARC incurred a deductible loss carryforward for Indiana of $40.0 million for the year ended December 31, 2025. The federal loss has an unlimited carryforward period, and the Indiana loss will expire in 2044. We believe it is more likely than not that the Indiana net operating loss carryforward will be realized before expiration, therefore no valuation allowance has been applied.

We participate in the IRS CAP, which provides the opportunity to resolve tax matters with the IRS before filing each year's consolidated federal income tax return. As of December 31, 2025, tax years through 2023 have been audited and are closed to further assessment. NiSource has not yet received a final acceptance letter from the IRS for its 2024 return. However, no adjustments are expected. The CAP Bridge for NiSource will not include the NIPSCO Holdings II partnership or NARC separate company C corporation income tax return for the 2025 tax year.
NiSource is obligated to report adjustments resulting from IRS audits or settlements to state taxing authorities. In addition, if NiSource utilizes net operating losses or tax credits generated in years for which the statute of limitations has expired, such amounts are generally subject to examination.

The statute of limitation period in Indiana and each of the state jurisdictions in which we operate remains open until the respective limitation period ends, which is generally within 3-4 years from the filing date. As of December 31, 2025 there were no open state income tax audits.
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15. Pension and Other Postemployment Benefits

NiSource provides defined contribution plans and noncontributory defined benefit retirement plans that cover our employees. Benefits under the defined benefit retirement plan reflect the employees' compensation, years of service and age at retirement. Additionally, NiSource provides health care and life insurance benefits for certain retired employees. Certain employees may become eligible for these benefits if they reach retirement age while working for us. The expected cost of such benefits is accrued during the employees' years of service. Current rates include postretirement benefit costs, including amortization of the regulatory assets that arose prior to inclusion of these costs in rates. For most plans, cash contributions are remitted to grantor trusts.

We are a participant in the consolidated NiSource defined benefit retirement plans which cover our employees, and, therefore, we are allocated a ratable portion of NiSource's grantor trusts and investment activity for the Plans in which its employees and retirees participate. As a result, we follow multiple employer accounting under the provision of accounting principles generally accepted in the United States of America. The allocation of fair value of assets is based upon the ratable share of plan funding and participant benefit payments. Investment activity within the trust occurs at the trust level, and we are allocated a portion of investment gains and losses based on our percentage of the total NiSource projected benefit obligation.

NiSource Pension and Other Postretirement Benefit Plans' Asset Management. NiSource's Board of Director's have delegated oversight of the pension and other postretirement benefit plans' assets to the NiSource Benefits Committee ("the Committee"). The Committee has adopted investment policy statements for the pension and other postretirement benefit plans' assets. For the pension plans, NiSource employs a liability-driven investing strategy. A total return approach is utilized for the other postretirement benefit plans' assets. A mix of diversified investments are used to maximize the long-term return of plan assets and hedge the liabilities at a prudent level of risk. The investment portfolio includes U.S. and non-U.S. equities, real estate, long-term and intermediate-term fixed income and alternative investments. Risk tolerance is established through careful consideration of plan liabilities, funded status, and asset class volatility. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

In determining the expected long-term rate of return on plan assets, historical markets are studied, relationships between equities and fixed income are analyzed and current market factors, such as inflation and interest rates are evaluated with consideration of diversification and rebalancing. Our expected long-term rate of return on assets is based on assumptions regarding target asset allocations and corresponding long-term capital market assumptions for each asset class. The pension plans' investment policy calls for a gradual reduction in the allocation of return-seeking assets (equities, real estate, and private equity) and a corresponding increase in the allocation of liability-hedging assets (fixed income) as the funded status of the plans' increase.

As of December 31, 2025 and December 31, 2024, the acceptable minimum and maximum ranges established by the policy for the pension and other postretirement benefit plans are as follows.

December 31, 202	Defined Benefit Pension Plan		Postretirement Benefit Plan	
Asset Category	**Minimum**	**Maximum**	**Minimum**	**Maximum**
Domestic Equities	10%	30%	0%	55%
International Equities	5%	15%	0%	25%
Fixed Income	65%	75%	20%	100%
Private Equity	0%	3%	0%	0%
Short-Term Investments	0%	10%	0%	10%

December 31, 2024	Defined Benefit Pension Plan		Postretirement Benefit Plan	
Asset Category	**Minimum**	**Maximum**	**Minimum**	**Maximum**
Domestic Equities	10%	30%	0%	55%
International Equities	5%	15%	0%	25%
Fixed Income	65%	75%	20%	100%
Private Equity	0%	3%	0%	0%
Short-Term Investments	0%	10%	0%	10%

The actual Pension Plan and Postretirement Plan Asset Mix at December 31, 2025 and December 31, 2024 are as follows.

	Defined Benefit Pension Assets [1]	December 31, 2025	Postretirement Benefit Plan Assets	December 31, 2025
Asset Class *(in millions)*	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	$ 187.2	20.2%	$ 9.5	51.8%
International Equities	95.3	10.3%	1.0	5.3%
Fixed Income	602.4	64.9%	7.6	41.6%
Cash/Other	42.9	4.6%	0.2	1.3%
Total	$ 927.8	100.0%	$ 14.3	100%

[1] Total includes accrued dividends and pending trades with brokers.

	Defined Benefit Pension Assets [1]	December 31, 2024	Postretirement Benefit Plan Assets	December 31, 2024
Asset Class *(in millions)*	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	$ 177.8	19.4%	$ 8.2	51.2%
International Equities	84.1	9.2%	0.8	4.9%
Fixed Income	612.0	66.7%	6.6	41.3%
Real Estate	2.7	0.3%	—	0%
Cash/Other	41.1	4.5%	0.4	2.6%
Total	$ 917.7	100%	$ 16.0	100%

[1] Total includes accrued dividends and pending trades with brokers.

The categorization of investments into the asset classes in the tables above are based on definitions established by the NiSource Benefits Committee.

Fair Value Measurements. The following table sets forth, by level within the fair value hierarchy, the pension and other postretirement benefits investment assets at fair value as of December 31, 2025 and 2024. Assets are classified in their entirety based on the observability of inputs used in determining the fair value measurement.

We use the following valuation techniques to determine fair value. For the year ended December 31, 2025, there were no significant changes to valuation techniques to determine the fair value of our pension and other postretirement benefits' assets. There were no material investment assets in the pension and other postretirement benefits trusts classified within Level 3 for the years ended December 31, 2025 and 2024.

Level 1 Measurements
Most common and preferred stocks are traded in active markets on national and international securities exchanges and are valued at closing prices on the last business day of each period presented. Cash is stated at cost, which approximates fair value, with the exception of cash held in foreign currencies which fluctuates with changes in the exchange rates. Short-term bills and notes are priced based on quoted market values.

Level 2 Measurements
Most U.S. Government Agency obligations, mortgage/asset-backed securities, and corporate fixed income securities are generally valued by benchmarking model-derived prices to quoted market prices and trade data for identical or comparable securities. To the extent that quoted prices are not available, fair value is determined based on a valuation model that includes inputs such as interest rate yield curves and credit spreads. Securities traded in markets that are not considered active are valued based on quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. Other fixed income includes futures and options which are priced on bid valuation or settlement pricing.

Level 3 Measurements
Investments with unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets and liabilities are classified as level 3 investments.

Not Classified
Commingled funds, private equity limited partnerships and real estate partnerships are not classified within the fair value hierarchy. Instead, these assets are measured at estimated fair value using the net asset value per share of the investments. Commingled funds' underlying assets are principally marketable equity and fixed income securities. Units held in commingled funds are valued at the unit value as reported by the investment managers. Private equity funds invest capital in non-public companies and real estate funds invest in commercial and distressed real estate directly or through related debt instruments. The fair value of these investments is determined by reference to the funds' underlying assets.

Fair Value Measurements at December 31, 2025:

(in millions)	December 31, 2025	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Pension plan assets:				
Cash	$ 0.3	$ 0.3	$ —	$ —
Fixed income securities				
Government	136.6	—	136.6	—
Corporate	326.8	—	326.8	—
Mortgages / Asset-backed securities	2.7	—	2.7	—
Other	0.1	—	0.1	
Derivatives				—
Assets	0.4	—	0.4	
Mutual funds				
U.S. multi-strategy	37.4	37.4	—	—
International equities	23.5	23.5	—	
Private equity limited partnerships (1)				—
U.S. multi-strategy (2)	1.7	—	—	—
International multi-strategy (3)	0.1	—	—	—
Commingled funds (1)				
Short-term money markets	34.8	—	—	—
U.S. equities	149.8	—	—	—
International equities	71.8	—	—	—
Fixed income	136.2	—	—	—
Pension plan assets subtotal	$ 922.2	$ 61.2	$ 466.6	$ —
Other postretirement benefit plan assets:				
Mutual funds				
U.S. equities	$ 9.5	$ 9.5	$ —	$ —
International equities	1.0	1.0	—	—
Fixed income	7.6	7.6	—	—
Commingled funds [1]				
Short-term money markets	0.2	—	—	—
Other postretirement benefit plan assets subtotal	$ 18.3	$ 18.1	$ —	$ —
Due to brokers, net [3]	(0.1)	—	(0.1)	—
Accrued investment income/dividends	5.5	5.5	—	—
Total pension and other postretirement benefit plan assets	$ 945.9	$ 84.8	$ 466.5	$ —

[1] This class of investments is measured at fair value using the net asset value per share and has not been classified in the fair value hierarchy.
[2] This class includes limited partnerships that invest in a diverse portfolio of private equity strategies, including buy-outs, growth capital, special situations and secondary markets, primarily inside the United States.
[3]This class includes limited partnerships that invest in a diverse portfolio of private equity strategies, including buy-outs, growth capital, special situations and secondary markets, primarily outside the United States.
[4] This class represents pending trades with brokers.

The table below sets forth a summary of unfunded commitments, redemption frequency and redemption notice periods for certain investments that are measured at fair value using the net asset value per share for the year ended December 31, 2025.

(in millions)	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
Commingled Funds				
Short-term money markets	$ 35.0	$ —	Daily	1 day
U.S. equities	149.8	—	Daily	1-10 days
International equities	71.8	—	Monthly	1-10 days
Fixed income	136.2	—	Daily	2 days
Private Equity and Real Estate Limited Partnerships [1]	1.8	6.5	N/A	N/A
Total	$ 394.6	$ 6.4		

[1] Private equity and real estate limited partnerships typically call capital over a 3-5 year period and pay out distributions as the underlying investments are liquidated. The typical expected life of these limited partnerships is 0-15 years, and these investments typically cannot be redeemed prior to liquidation.

Fair Value Measurements at December 31, 2024:

(in millions)	December 31, 2024	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Pension plan assets:				
Cash	$ 0.8	$ 0.8	$ —	$ —
Fixed income securities				
Government	128.3	—	128.3	—
Corporate	334.2	—	334.2	—
Mortgages / Asset-backed securities	2.5	—	2.5	—
Mutual funds				
U.S. multi-strategy	38.5	38.5	—	—
International equities	39.3	39.3	—	—
Private equity limited partnerships (1)				
U.S. multi-strategy (2)	2.1	—	—	—
International multi-strategy (3)	0.6	—	—	—
Real estate (1)	2.7	—	—	—
Commingled funds (1)				
Short-term money markets	31.5	—	—	—
U.S. equities	139.3	—	—	—
International equities	44.9	—	—	—
Fixed income	147.0	—	—	—
Pension plan assets subtotal	$ 911.7	$ 78.6	$ 465.0	$ —
Other postretirement benefit plan assets:				
Mutual funds				
U.S. equities	$ 8.2	$ 8.2	$ —	$ —
International equities	0.8	0.8	—	—
Fixed income	6.6	6.6	—	—
Commingled funds (3)				
Short-term money markets	0.4	—	—	—
Other postretirement benefit plan assets subtotal	$ 16.0	$ 15.6	$ —	$ —
Due to brokers, net (4)	0.1	—	0.1	—
Accrued investment income/dividends	5.9	5.9	—	—
Total pension and other postretirement benefit plan assets	$ 933.7	$ 100.1	$ 465.1	$ —

(1) This class of investments is measured at fair value using the net asset value per share and has not been classified in the fair value hierarchy.
(2) This class includes limited partnerships that invest in a diverse portfolio of private equity strategies, including buy-outs, growth capital, special situations and secondary markets, primarily inside the United States.
(3)This class includes limited partnerships that invest in a diverse portfolio of private equity strategies, including buy-outs, growth capital, special situations and secondary markets, primarily outside the United States.
(4) This class represents pending trades with brokers.

The table below sets forth a summary of unfunded commitments, redemption frequency and redemption notice periods for certain investments that are measured at fair value using the net asset value per share for the year ended December 31, 2024.

(in millions)	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
Commingled Funds				
Short-term money markets	$ 31.9	$ —	Daily	1 day
U.S. equities	139.3	$ —	Daily	1-5 days
International equities	44.9	$ —	Monthly	10-30 days
Fixed income	147.0	$ —	Daily	3 days
Private Equity and Real Estate Limited Partnerships (1)	5.4	$ 6.4	N/A	N/A
Total	$ 368.5	$ 6.4		

(1) Private equity and real estate limited partnerships typically call capital over a 3-5 year period and pay out distributions as the underlying investments are liquidated. The typical expected life of these limited partnerships is 0-15 years, and these investments typically cannot be redeemed prior to liquidation.

Our Pension and Other Postretirement Benefit Plans' Funded Status and Related Disclosure. The following table provides a reconciliation of the plans' funded status and amounts reflected in our Consolidated Balance Sheets at December 31, based on a December 31 measurement date.

	Pension Benefits		**Other Postretirement Benefits**	
(in millions)	**2025**	**2024**	**2025**	**2024**
Change in projected benefit obligation (1)				
Benefit obligation at beginning of year	**$ 863.8**	$ 941.1	**$ 232.3**	$ 247.8
Service cost	**12.6**	13.9	**2.5**	3.2
Interest cost	**43.5**	43.8	**11.5**	11.6
Plan participants' contributions	**—**	—	**1.7**	1.6
Plan amendments	**—**	—	**(15.3)**	—
Actuarial (gain)/loss (2)	**21.7**	(55.7)	**(0.4)**	(12.6)
Benefits paid	**(80.2)**	(79.3)	**(18.7)**	(19.3)
Projected benefit obligation at end of year	**$ 861.4**	$ 863.8	**$ 213.6**	$ 232.3
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 917.8**	$ 975.3	**$ 16.1**	$ 14.3
Actual return on plan assets	**88.6**	21.8	**2.2**	2.3
Employer contributions	**—**	—	**17.0**	17.3
Plan participants' contributions	**—**	—	**1.7**	1.6
Benefits paid	**(80.2)**	(79.3)	**(18.7)**	(19.3)
Fair value of plan assets at end of year	**$ 926.2**	$ 917.8	**$ 18.3**	$ 16.2
Funded status at end of year	**$ 64.8**	$ 54.0	**$ (195.3)**	$ (216.3)
Amounts recognized on the Consolidated Balance Sheets consist of:				
Noncurrent assets	**$ 64.8**	$ 54.0	**$ —**	$ —
Current liabilities	**—**	—	**—**	(1.5)
Noncurrent liabilities	**—**	—	**(195.3)**	(214.8)
Net amount recognized at end of year (3)	**$ 64.8**	$ 54.0	**$ (195.3)**	$ (216.3)
Amounts recognized in accumulated other comprehensive income or regulatory asset/liability (4)				
Unrecognized prior service cost/(credit)	**$ 0.2**	$ 0.3	**$ (16.1)**	$ (4.1)
Unrecognized actuarial loss	**$ 333.7**	354.6	**$ 23.1**	27.6
Net amount recognized at end of year	**$ 333.9**	$ 354.9	**$ 7.0**	$ 23.5

(1) The change in benefit obligation for Pension Benefits represents the change in Projected Benefit Obligation while the change in benefit obligation for Other Postretirement Benefits represents the change in accumulated postretirement benefit obligation.
(2) The pension actuarial loss (gain) as of December 31, 2025 and December 31, 2024 was primarily driven by the decrease in discount rates interest rate movements and the increase in discount rates interest rate movements, respectively. The postretirement benefit actuarial (gain) as of December 31, 2025 and December 31, 2024 was primarily driven by claims experience changes in trend rates.
(3) We recognize on our Consolidated Balance Sheets the underfunded and overfunded status of our defined benefit postretirement plans measured as the difference between the fair value of the plan assets and the benefit obligation.
(4) We determined that the future recovery of pension and other postretirement benefits costs is probable. We recorded regulatory assets of $341.0 million as of December 31, 2025 and $378.5 million as of December 31 2024 that would otherwise have been recorded to accumulated other comprehensive income (loss).

Our accumulated benefit obligation for our pension plan was $853.6 million and $854.9 million as of December 31, 2025 and 2024, respectively. The accumulated benefit obligation at each date is the actuarial present value of benefits attributed by the pension benefit formula to employee service rendered prior to that date and based on current and past compensation levels. The accumulated benefit obligation differs from the projected benefit obligation disclosed in the table above in that it includes no assumptions about future compensation levels.

Our pension plan was overfunded by $64.8 million at December 31, 2025 and overfunded by $54.0 million at December 31, 2024. The improvement in the funded status was primarily due to actual return on assets exceeding the expected return on assets, partially offset by a decrease in discount rates. We did not contribute to our pension plan in either 2025 or 2024.

Our other postretirement benefit plans were underfunded by $195.3 million at December 31, 2025 and underfunded by $216.1 million at December 31, 2024. The change in funded status was primarily due to actual return on assets exceeding the expected return on assets, partially offset by a decrease in discount rates. We contributed $17.0 million and $17.3 million to our other postretirement benefits plans in 2025 and 2024, respectively.

The following table provides the key assumptions that were used to calculate the pension and other postretirement benefits obligations for our various plans as of December 31.

	Pension Benefits		**Other Postretirement Benefits**	
	2025	2024	**2025**	2024
Weighted-average assumptions to determine benefit obligation				
Discount rate	**5.32%**	5.60%	**5.45%**	5.66%
Rate of compensation increases	**4.00%**	4.00%	**N/A**	N/A
Interest crediting rates	**4.00%**	4.00%	**N/A**	N/A
Heath care trend rates				
Trend for new year	**N/A**	N/A	**9.60%**	9.84%
Ultimate trend	**N/A**	N/A	**4.75%**	4.75%
Year ultimate trend reached	**N/A**	N/A	**2034**	2033

We expect to make no contributions to our pension plan and expect to make contributions of approximately $15.5 million to our postretirement medical and life plans in 2026.

The following table provides benefits expected to be paid in each of the next five fiscal years and in the aggregate for the five fiscal years thereafter. The expected benefits are estimated based on the same assumptions used to measure our benefit obligation at the end of the year and include benefits attributable to the estimated future service of employees.

(in millions)		Pension Benefits	Other Postretirement Benefits
Year(s)			
2026	$	91.9 $	15.5
2027		81.3	15.9
2028		78.8	16.1
2029		76.6	16.3
2030		74.9	16.7
2031-2035		349.8	85.3

The following table provides the components of the plans' actuarially determined net periodic benefits costs for each of the three years ended December 31, 2025, 2024 and 2023.

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2025**	2024	2023	**2025**	2024	2023
Components of Net Periodic Benefit Cost (Income) [1]						
Service cost	**$ 12.6**	$ 13.9	$ 13.0	**$ 2.5**	$ 3.2	$ 3.1
Interest cost	**43.5**	43.8	45.8	**11.5**	11.6	11.6
Expected return on assets	**(64.3)**	(66.1)	(64.5)	**(1.3)**	(1.2)	(1.0)
Amortization of prior service cost/(credit)	**0.1**	0.1	0.1	**(3.2)**	(2.8)	(2.9)
Recognized actuarial loss	**18.3**	20.3	22.8	**1.1**	2.0	2.1
One-Time Charge	**—**	—	—	**2.1**	—	—
Total Net Periodic Benefit Cost (Income)	**$ 10.2**	$ 12.0	$ 17.2	**$ 12.7**	$ 12.8	$ 12.9

[1] Service cost is presented in "Operation and maintenance" and non-service cost components are presented within "Other, net", on the Statements of Consolidated Operations.

The following table provides the key assumptions that were used to calculate the net period benefits costs for our various plans.

	Pension Benefits			Other Postretirement Benefits		
	2025	2024	2023	**2025**	2024	2023
Weighted-Average Assumptions to Determine Net Periodic Benefit Cost						
Discount rate - service cost	**5.77%**	5.08%	5.27%	**5.92%**	5.15%	5.32%
Discount rate - interest cost	**5.30%**	4.88%	5.06%	**5.33%**	4.87%	5.06%
Expected long-term rate of return on plan assets	**7.35%**	7.10%	7.00%	**8.11%**	8.27%	8.20%
Rate of compensation increases	**4.00%**	4.00%	4.00%	**N/A**	N/A	N/A
Interest crediting rates	**4.00%**	4.00%	4.00%	**N/A**	N/A	N/A

We assumed a 7.35% and 8.11% rate of return on pension and other postretirement plan assets, respectively, for our calculation of 2025 pension benefits and other postretirement benefits costs. These rates were primarily based on asset mix and historical rates of return and were adjusted in 2025 due to changes in asset allocation and projected market returns.

The following table provides other changes in plan assets and projected benefit obligations recognized in regulatory assets or liabilities.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2025**	2024	**2025**	2024
Other Changes in Plan Assets and Projected Benefit Obligations Recognized in Regulatory Asset or Liability				
Net prior service cost	**$ —**	$ —	**$ (15.3)**	$ —
Net actuarial loss (gain)	**(2.7)**	(11.3)	**(1.3)**	(13.7)
One-time Charge	**—**	—	**(2.1)**	
Less: amortization of prior service (credit)/cost	**(0.1)**	(0.1)	**3.2**	2.8
Less: amortization of net actuarial gain	**(18.3)**	(20.3)	**(1.1)**	(1.9)
Total Recognized in Regulatory Asset or Liability	**$ (21.1)**	$ (31.7)	**$ (16.6)**	$ (12.8)
Amount Recognized in Net Periodic Benefits Cost and Regulatory Asset or Liability	**$ (10.9)**	$ (19.8)	**$ (3.9)**	$ (0.1)

In August 2025, NiSource communicated to plan participants of one of its OPEB plans the intention to move from a group self insured Medicare supplemental health plan to a Sponsored Health Reimbursement Account, with eligible retirees electing coverage through a Healthcare Exchange, effective on January 1, 2026. Given the intention of the plan and communication to participants, this was considered a plan amendment at the time of communication. This plan amendment triggered remeasurement of this plan, resulting in a decrease to our OPEB regulatory asset of $8.9 million and a decrease to our OPEB liability of $8.9 million. Net periodic OPEB benefit cost for 2025 decreased by $0.9 million as a result of the interim remeasurement. Additionally, this change resulted in the Net prior service (credit) cost of $(15.3) million in the table above.

In line with the remeasurement, key inputs, economic assumptions, and demographic assumptions changed to calculate the updated OPEB benefit obligation and the net periodic benefit cost at the interim remeasurement date for the plan that triggered settlement accounting. For remeasurement, NiSource used a weighted-average discount rate of 5.53%, a weighted-average health care trend rate of 9.97% for next year and ultimate trend rate of 4.75% to be reached in 2034, and weighted-average expected return on assets of 6.88%.

16. Leases.

Lease Descriptions. We are the lessee for substantially all of our leasing activity, which includes operating and finance leases for corporate and field offices, railcars, land and fleet vehicles. Our corporate and field office leases and certain land leases have remaining terms between 2 and 38 years with options to renew the leases for up to 35 years. We lease railcars to transport coal to and from our electric generation facilities. Our railcars are specifically identified in the lease agreements which have remaining lease terms between 1 and 2 years with options to renew for 1 year. Our fleet vehicles include trucks, trailers and equipment that have been customized specifically for use in the utility industry. We lease fleet vehicles for 1-year terms, after which we have the option to extend on a month-to-month basis or terminate with written notice. We elected the short-term lease practical expedient, allowing us to not recognize ROU assets or lease liabilities for all leases with a term of 12 months or less. ROU assets and liabilities on our Consolidated Balance Sheets do not include obligations for possible fleet vehicle lease renewals beyond the initial lease term. While we have the ability to renew these leases beyond the initial term, we are not reasonably certain to do so.

We have not provided material residual value guarantees for our leases, nor do our leases contain material restrictions or covenants. Lease contracts containing renewal and termination options are mostly exercisable at our sole discretion. Certain of our real estate and railcar leases include renewal periods in the measurement of the lease obligation if we have deemed the renewals reasonably certain to be exercised.

With respect to service contracts involving the use of assets, if we have the right to direct the use of the asset and obtain substantially all economic benefits from the use of an asset, we account for the service contract as a lease. Unless specifically provided to us by the lessor, we utilize NiSource's collateralized incremental borrowing rate commensurate to the lease term as the discount rate for all of our leases. ASC 842 permits a lessee, by class of underlying asset, not to separate nonlease components from lease components. Our policy is to apply this expedient for our leases of fleet vehicles and railcars when calculating their respective lease liabilities.

Lease costs for the years ended December 31, 2025 and December 31, 2024 are presented in the table below. These costs include both amounts recognized in expense, amounts capitalized as part of the cost of another asset, and amounts deferred to a regulatory asset. Statements of Consolidated Operations presentation for these costs (when ultimately recognized on the income statement) is also included.

Year Ended December 31, *(in millions)*	Statements of Consolidated Operations Classification	**2025**	2024
Finance lease cost			
Amortization of right-of-use assets	Depreciation and amortization	**$ 7.8**	$ 4.8
Interest on lease liabilities	Other, net	**9.3**	4.7
Total finance lease cost		**17.1**	9.5
Operating lease cost	Operating and maintenance	**6.1**	5.3
Total lease cost		**$ 23.2**	$ 14.8

Our right-of-use assets and liabilities are presented in the following lines on the Consolidated Balance Sheets:

As of December 31, *(in millions)*	Classification on Consolidated Balance Sheets	**2025**	2024
Assets			
Finance leases	Net Property, Plant and Equipment	**$ 167.3**	$ 127.7
Operating leases	Deferred charges and other	**6.8**	8.1
Total leased assets		**$ 174.1**	$ 135.8
Liabilities			
Current			
Finance leases	Current portion of long-term debt	**8.6**	$ 6.8
Operating leases	Other accruals	**3.5**	3.5
Noncurrent			
Finance leases	Long-term debt, excluding amounts due within one year	**156.8**	117.4
Operating leases	Other noncurrent liabilities and deferred credits	**3.3**	4.7
Total lease liabilities		**$ 172.2**	$ 132.4

Other pertinent information related to leases was as follows:

Year Ended December 31, *(in millions)*	**2025**	2024
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows used for finance leases	**$ 7.8**	$ 3.7
Operating cash flows used for operating leases	**6.2**	5.3
Financing cash flows used for finance leases	**5.5**	3.1
Right-of-use assets obtained in exchange for lease obligations		
Finance leases	**$ 46.7**	$ 65.5
Operating leases	**4.5**	3.6

at December 31, *(in millions)*	**2025**	2024
Weighted-average remaining lease term (years)		
Finance leases	**28.9**	28.9
Operating leases	**3.8**	3.8
Weighted-average discount rate		
Finance leases	**5.5 %**	5.5 %
Operating leases	**4.1 %**	4.1 %

Maturities of our lease liabilities as of December 31, 2025 were as follows:

As of December 31, 2025 *(in millions)*	Total	Finance Leases	Operating Leases
2026	$ 17.8	$ 14.1	$ 3.7
2027	15.5	14.1	1.4
2028	14.1	13.4	0.7
2029	8.9	8.4	0.5
2030	10.2	9.9	0.3
Thereafter	281.3	280.7	0.6
Total lease payments	347.8	340.6	7.2
Less: Imputed interest	(175.6)	(175.2)	(0.4)
Total	$ 172.2	$ 165.4	$ 6.8
Reported as of December 31, 2025			
Short-term lease liabilities	160.3	156.8	3.5
Long-term lease liabilities	11.9	8.6	3.3
Total lease liabilities	$ 172.2	$ 165.4	$ 6.8

17. Other Commitments and Contingencies

A. Contractual Obligations. We have certain contractual obligations requiring payments at specified periods. The obligations include long-term debt, lease obligations, energy commodity contracts and obligations for various services including pipeline capacity. The total contractual obligations in existence at December 31, 2025 and their maturities were as follows.

(in millions)	Total	2026	2027	2028	2029	2030	After
Long-term debt	$ 5,134.0	$ —	$ 58.0	$ —	$ 120.0	$ —	$ 4,956.0
Interest payments on long-term debt	6,342.1	248.6	260.2	256.9	256.9	249.2	5,070.3
Finance leases [(1)]	340.6	14.1	14.1	13.4	8.4	9.9	280.7
Operating leases [(2)]	7.2	3.7	1.4	0.7	0.5	0.3	0.6
Energy commodity contracts	476.9	315.9	116.7	9.3	7.6	4.6	22.8
Pipeline service obligations	481.9	109.0	108.2	101.3	84.6	59.3	19.5
Other service obligations	5.5	3.2	1.2	1.1	—	—	—
Plant equipment purchase obligations	59.2	51.6	7.6	—	—	—	—
Other liabilities [(3)]	70.9	26.9	8.9	8.3	8.4	8.0	10.4
Total Contractual Obligations	$ 12,918.3	$ 773.0	$ 576.3	$ 391.0	$ 486.4	$ 331.3	$ 10,360.3

[(1)] Long-term debt balance excludes a de minimis amount of unamortized discounts and unamortized finance leases of $165.4 million.
[(2)] Finance lease payments shown above are inclusive of interest totaling $175.2 million.
[(3)] Operating lease payments shown above are inclusive of interest totaling $0.4 million. Operating lease balances do not include obligations for possible fleet vehicle lease renewals beyond the initial lease term. While we have the ability to renew these leases beyond the initial term, we are not reasonably certain to do so as they are renewed month-to-month after the first year.
[(4)] Other liabilities shown above are primarily related to ongoing maintenance service agreements for our renewable joint ventures and wholly owned renewables as well as 2026 expected employer contributions on the postretirement benefit plan.

Purchase and Service Obligations. We have entered into various purchase and service agreements whereby we are contractually obligated to make certain minimum payments in future periods. Our energy commodity contracts are for the purchase of physical quantities of natural gas, electricity, coal, and purchases of electric capacity. Our service obligations, consisting of pipeline service obligations, encompass a broad range of business support and maintenance functions which are generally described below. Our plant equipment purchase obligations are for plant equipment, typically for generation assets, with long lead times that require payments made over time.

We have entered into various energy commodity contracts to purchase physical quantities of natural gas, electricity, coal, and purchases of electric capacity. These amounts represent the minimum quantity of these commodities we are obligated to purchase at both fixed and variable prices. To the extent contractual purchase prices are variable, obligations disclosed in the table above are valued at market prices as of December 31, 2025.

We have PPAs representing approximately 1,200 MW of capacity, with contracts expiring between 2038 and 2045. No minimum quantities are specified within these agreements due to the variability of electricity generation, so no amounts related to these contracts are included in the table above. Upon early termination of one of these agreements by us for any reason (other than material breach by the counterparties), we may be required to pay a termination charge that could be material depending on the events giving rise to termination and the timing of the termination.

We have pipeline service agreements that provide for pipeline capacity, transportation and storage services. These agreements, which have expiration dates ranging from 2027 to 2038, require us to pay fixed monthly charges.

We have contracts with three rail operators providing coal transportation services for which there are certain minimum payments. These service contracts extend for various periods from 2026 through 2028.

B. Guarantees and Indemnities. NiSource has provided guarantees related to its future performance under BTAs for our renewable generation projects. At December 31, 2025 and 2024, the guarantees for multiple BTAs totaled $27.2 million and $1,127.5 million, respectively. The amount of each guaranty will decrease upon the substantial completion of the construction of the facilities. See "-E. Other Matters – Generation Transition," below for more information.

We provide guarantees related to some of our rail and pipeline service agreements. If we do not meet our contractual obligations under the terms of these agreements, we would be required to pay up to a maximum of $4.0 million.

C. Legal Proceedings. From time to time, various legal and regulatory claims and proceedings are pending or threatened against us. While the amounts claimed may be substantial, we are unable to predicts with certainty the ultimate outcome of such claims and proceedings. We establish reserves whenever we believe it to be appropriate for pending litigation matters. However, the actual results of resolving the pending litigation matters may be substantially higher than the amounts reserved. If one or more other matters were decided against us, the effects could be material to our results of operations in the period in which we would be required to record or adjust the related liability and could also be material to our cash flows in the periods that we would be required to pay such liability. Due to the inherent uncertainty of litigation, there can be no assurance that the resolution of any particular claim, proceeding or investigation would not have a material adverse effect on our results of operations, financial position or liquidity.

Other Claims and Proceedings. We are also party to certain other claims, regulatory and legal proceedings arising in the ordinary course of business, and based upon an investigation of these matters and discussion with legal counsel, we believe the ultimate outcome of such other legal proceedings to be individually, or in aggregate, not material at this time.

D. Environmental Matters. Our operations are subject to environmental statutes and regulations related to air quality, water quality, hazardous waste and solid waste. We believe that we are in substantial compliance with the environmental regulations currently applicable to our operations.

It is management's continued intent to address environmental issues in cooperation with regulatory authorities in such a manner as to achieve mutually acceptable compliance plans. However, there can be no assurance that fines and penalties will not be incurred. Management expects the majority of environmental assessment and remediation costs and asset retirement costs, further described below, to be recoverable through rates. See Note 10, "Asset Retirement Obligations," and Note 11, "Regulatory Matters," for additional detail.

As of December 31, 2025 and 2024, we had recorded a liability of approximately $37.6 million and $39.0 million, respectively, to cover environmental remediation at various sites. This liability is included in "Other accruals" and "Other noncurrent liabilities and deferred credits" on the Consolidated Balance Sheets. We recognize costs associated with environmental remediation obligations when the incurrence of such costs is probable and the amounts can be reasonably estimated. The original estimates for remediation activities may differ materially from the amount ultimately expended. The actual future expenditures depend on many factors, including laws and regulations, the nature and extent of impact and the method of remediation. These expenditures are not currently estimable at some sites. We periodically adjust our liability as information is collected and estimates become more refined.

CERCLA. We are a potentially responsible party at waste disposal sites under the CERCLA and similar state laws. Under CERCLA, each potentially responsible party can be held jointly, severally and strictly liable for the remediation costs as the EPA, or state, can allow the parties to pay for remedial action or perform remedial action themselves and request reimbursement from the potentially responsible parties. We have retained CERCLA environmental liabilities, including remediation liabilities, associated with certain current and former operations. At this time, we cannot estimate the full cost of remediating properties that have not yet been investigated, but it is possible that the future costs could be material to the Consolidated Financial Statements.

MGP. We maintain a program to identify and investigate former MGP sites where we or predecessors may have liability. The program has identified 25 such sites where liability is probable. Remedial actions at many of these sites are being overseen by state or federal environmental agencies through consent agreements or voluntary remediation agreements.

We utilize a probabilistic model to estimate our future remediation costs related to our MGP sites. The model was prepared with the assistance of a third party and incorporates our experience and general industry experience with remediating MGP sites. We complete an annual refresh of the model in the second quarter of each fiscal year. No material changes to the estimated future remediation costs were identified during the update completed as of June 30, 2025. Our total estimated liability related to the facilities subject to remediation was $30.4 million and $33.4 million at December 31, 2025 and 2024, respectively. The liability represents our best estimate of the probable cost to remediate the MGP sites. Our model indicates that it is reasonably possible that remediation costs could vary by as much as $12.9 million in addition to the costs noted above. Remediation costs are estimated based on the best available information, applicable remediation standards at the balance sheet date and experience with similar facilities.

CCRs. We continue to meet the compliance requirements established by the EPA for the regulation of CCRs. The CCR rule requirements currently in effect required revisions to previously recorded legal obligations associated with the retirement of certain of our facilities. The actual asset retirement costs related to the CCR rule may vary substantially from the estimates used to record the increased asset retirement obligation due to the uncertainty about the requirements that will be established by environmental authorities, compliance strategies that will be used, and the preliminary nature of available data used to estimate costs. As allowed by the rule, we will continue to collect data over time to determine the specific compliance solutions and associated costs and, as a result, the actual costs may vary.

On May 8, 2024, the EPA finalized changes to the current CCR regulations ("Legacy CCR Rule") which address inactive surface impoundments at inactive facilities, referred to as legacy impoundments, and CCR management units ("CCRMUs") at inactive and active facilities. The rule largely requires these newly regulated units to conform to existing requirements, such as groundwater monitoring, closure requirements, and post-closure care. During 2025, we accrued an additional $48.9 million to cover probable and estimable compliance activities associated with the Legacy CCR Rule. We continue to assess whether existing legal obligations associated with the retirement of certain facilities must be revised and to estimate probable additional required asset retirement costs. We expect to receive recovery of any such costs through existing and future depreciation rates.

E. Other Matters

Generation Transition. In October 2024, we contracted with a developer to convert the previously approved Templeton PPA to a BTA and in February 2025 filed a CPCN with the IURC seeking approval of the full ownership BTA structure. In September 2025, the IURC granted us a CPCN to acquire Templeton through the full ownership BTA structure. Our purchase obligation under Templeton is dependent on timely completion of construction. Certain agreements require us to make partial payments upon the developer's completion of significant construction milestones.

In January 2025, the Fairbanks project achieved mechanical completion, resulting in us making a $336.6 million payment to the developer. In May 2025, the Fairbanks project achieved substantial completion, resulting in us making a $141.4 million payment to the developer in June 2025. In December 2025, the Fairbanks project achieved final completion, resulting in us making a $3.6 million payment to the developer.

In January 2025, the Dunns Bridge II project achieved substantial completion, resulting in us making a $217.6 million payment to the developer in February 2025. In October 2025, the Dunns Bridge II project achieved final completion resulting in a us making a $4.2 million payment to the developer.

In June 2025, the Gibson project achieved mechanical completion, resulting in us making a $262.4 million payment to the developer. In August 2025, the Gibson project achieved substantial completion, resulting in us making a $133.7 million payment to the developer in September 2025.

Minority Interest Transaction. In December 2023, pursuant to the terms of the BIP Purchase Agreement and simultaneously with the closing of the NIPSCO Minority Interest Transaction, Blackstone, NIPSCO Holdings I, NIPSCO Holdings II and NiSource entered into an Amended and Restated Limited Liability Company Agreement of NIPSCO Holdings II. In January 2024, BIP transferred a 4.5% portion of its equity interest to one of its affiliates and the members of NIPSCO Holdings II entered into a Second Amended and Restated Limited Liability Company Operating Agreement of NIPSCO Holdings II. In October 2025, the members of NIPSCO Holdings II entered into a Third Amended and Restated LLC Agreement of NIPSCO Holdings II (the "Amended LLC Agreement"), which, among other changes, increased the amount and time period for additional mandatory capital contributions required to be contributed by the members affiliated with Blackstone by $175 million and seven years, which obligation is backed by an Equity Commitment Letter from Blackstone or an affiliate thereof, and amended certain provisions to facilitate NIPSCO Holdings II and its subsidiaries' provision of electric service to data center customers (and related activities) and their related contracts and arrangements with Generation Holdings II and its subsidiaries. The members of NIPSCO Holdings II that are affiliates of Blackstone must vote their equity holdings under the Amended LLC Agreement as one investor.

ADS Contract. In September 2025, NIPSCO entered into an agreement with ADS, a wholly-owned subsidiary of Amazon.com, Inc., under which NIPSCO will provide electricity to ADS' data centers. Under the ADS Contract, which is pending IURC approval, NIPSCO will provide electric service to ADS pursuant to a capacity commitment beginning in 2027 and increasing annually to 2,400 MW by the end of 2032 and will construct up to 3,000 MW of dispatchable generation to provide such electric service. The ADS Contract's initial term ends 15 years after the initial energization of ADS' initial data center.

In order to meet demand under the ADS Contract, NIPSCO has entered into a PPA with GenCo, which is pending IURC approval and contains terms and provisions substantially similar to the ADS Contract, such that economic benefits (except savings that are expected to be passed to retail customers as described above) and obligations of the ADS Contract as they relate to the Generation Assets (as defined below) are expected to be borne by GenCo and NiSource, as GenCo's ultimate parent company, rather than NIPSCO. See Footnote 4 Noncontrolling Interest for a discussion on the VIE considerations between NIPSCO and GenCo.

Either party may terminate the ADS Contract upon certain defaults or failure to obtain necessary related approvals from the IURC and FERC. ADS may terminate the ADS Contract for convenience following certain notice periods and also has a one-time option (exercisable no later than March 31, 2029) to halve the committed capacity under the ADS Contract to 1,200 MW commencing January 31, 2032. If ADS terminates for convenience, exercises its reduction option or defaults, NIPSCO or its affiliates will be reimbursed for investment costs, subject to agreed caps based on cost estimates by year as of signing. NIPSCO's aggregate liability, including liquidated damages, is subject to a cap. In addition, under the ADS Contract, NIPSCO has direct contractual obligations to ADS to, among other things, construct the Generation Assets and deliver committed electric capacity in fixed amounts by certain dates.

18. Other, Net

The following table displays the components of Other, Net included on the Statements of Consolidated Operations:

Year Ended December 31, *(in millions)*		2025	2024	2023
Interest income	**$**	**1.4**	$ 1.6	$ 11.2
AFUDC equity		**28.2**	72.4	23.0
Pension and other postretirement non-service costs [1]		**(7.7)**	(7.7)	(14.0)
Tax penalty		**(1.3)**	—	—
Heating assistance		**(2.1)**	(0.5)	(0.8)
Miscellaneous		**1.9**	(0.4)	0.5
Total Other, Net	**$**	**20.4**	$ 65.4	$ 19.9

[1] See Note 15, "Pension and Other Postretirement Benefits" for additional information.

19. Interest Expense, Net

The following table displays the components of Interest expense, Net included on the Statements of Consolidated Operations:

Year Ended December 31, *(in millions)*		2025	2024	2023
Interest on long-term debt	**$**	**4.4**	$ 4.4	$ 4.4
Interest on long-term debt - affiliated		**265.0**	202.5	152.4
Interest on short-term borrowings		**2.3**	1.7	19.7
Interest on finance lease obligations		**9.3**	4.7	1.7
Accounts receivable securitization fees		**0.8**	0.7	1.3
Allowance for borrowed funds and interest capitalized during construction		**(22.4)**	(24.9)	(14.5)
Debt-based post-in-service carrying charges		**(27.1)**	(5.2)	(8.3)
Other		**4.5**	3.8	3.7
Total Interest expense, Net	**$**	**236.8**	$ 187.7	$ 160.4

20. Supplemental Disclosures of Cash Flow Information

The following table displays the components of Changes in Assets and Liabilities on the Statements of Consolidated Cash flows for the years ended December 31, 2025, 2024, and 2023.

Year Ended December 31, (in millions)		2025	2024	2023
Accounts receivable - affiliated	**$**	**78.7**	$ (56.1)	$ (24.6)
Accounts receivable		**(148.9)**	(40.9)	59.3
Gas storage and other inventories		**(12.0)**	39.4	60.8
Accounts payable - affiliated		**(89.4)**	89.8	34.2
Accounts payable		**12.5**	48.3	(28.4)
Exchange gas receivable/payable		**22.0**	(76.5)	136.8
Other accruals		**(13.9)**	17.6	(40.7)
Prepayments and other current assets		**(9.0)**	(12.2)	(9.6)
Regulatory assets/liabilities		**12.5**	(1.1)	(16.0)
Postretirement and postemployment benefits		**(31.0)**	(37.1)	(10.9)
Deferred charges and other noncurrent assets		**(18.2)**	(20.1)	(31.9)
Other noncurrent liabilities and deferral credits		**(1.4)**	4.2	6.5
Total Changes in Assets and Liabilities	**$**	**(198.1)**	$ (44.7)	$ 135.5

The following table provides additional information regarding our Consolidated Statements of Cash Flows for the years ended December 31, 2025, 2024, and 2023.

Year Ended December 31, *(in millions)*		2025	2024	2023
Non-cash transactions:				
Capital expenditures included in current liabilities	**$**	**256.0**	$ 201.8	$ 186.5
Assets acquired under a finance lease		**46.7**	65.5	48.0
Assets acquired under an operating lease		**4.5**	4.1	2.2
Assets recorded for asset retirement obligations [1]		**81.9**	277.5	63.0
Schedule of interest and income taxes paid:				
Cash paid for interest on long-term debt, net of interest capitalized - affiliated	**$**	**260.0**	$ 221.4	$ 163.5
Cash paid for interest on long-term debt, net of interest capitalized		**4.4**	2.8	38.0
Cash paid for interest on finance leases		**7.8**	3.1	1.7
Cash paid/ to NiSource for income taxes		**3.4**	40.8	40.8

[1] See Note 10, "Asset Retirement Obligations," for additional information.

21. Subsequent Events

In March 2026, we experienced damage to our solar generation facilities at Dunn's Bridge I and Dunn's Bridge II due to an extreme wind event. We are still evaluating the extent of this storm damage to the facilities and expect that damage would be partly covered by insurance proceeds.

14. Income Taxes (FERC Only)

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws involves uncertainty, since tax authorities may interpret the laws differently.

The Company is a pass-through entity for income tax purposes, but for regulatory accounting purposes the following information is presented. When income tax expense is recorded the offset is to current and deferred income tax accounts on the balance sheet. Deferred income tax assets and liabilities are determined based on differences between financial reporting and tax basis of assets and liabilities. Where a reduction in the net deferred tax liabilities will be passed through to customers in regulated rates, the Company establishes a corresponding regulatory liability.

Income Tax Expense. The components of income tax expense (benefit) were as follows.

Year Ended December 31, *(in millions)*		2025	2024	2023
Income Taxes				
Current				
Federal		**(17.1)**	21.9	32.1
State		**2.1**	3.8	6.2
Total Current Expense (Benefit)		**(15.0)**	**25.7**	**38.3**
Deferred				
Federal				
Taxes before operating loss carryforwards and investment credits		**116.9**	75.6	(8.9)
Tax utilization expense of operating loss carryforwards		**18.7**	(9.4)	21.3
Investment Tax Credits		**(0.3)**	(0.3)	(2.1)
State		**22.0**	14.9	13.9
Total Deferred Expense (Benefit)		**157.3**	**80.8**	**24.2**
Deferred Investment Tax Credits		**(0.2)**	(0.2)	(0.3)
Income Taxes from Continuing Operations	**$**	**142.1 $**	**106.3 $**	**62.2**

Statutory Rate Reconciliation. The following table represents a reconciliation of income tax expense at the statutory federal income tax rate to the actual income tax expense from continuing operations.

Year Ended December 31, *(in millions)*		2025			2024			2023	
Book income (loss) before income taxes	**$**	**785.1**		$	657.5		$	401.1	
Tax expense (benefit) at statutory federal income tax rate		**164.9**	**21.0%**		138.1	21.0%		84.2	21.0%
State income taxes, net of federal income tax benefit		**15.0**	**1.9%**		11.5	1.7%		9.2	2.3%
Tax Credits									
Investment Tax Credit		**(40.4)**	**(5.1%)**		(18.1)	(2.8%)		—	0.0%
Production Tax Credit		**(50.6)**	**(6.4%)**		(6.9)	(1.0%)		—	0.0%
Regulatory Adjustments									
Excess Deferred Income Taxes - ITC / PTC		**84.9**	**10.8%**		25.0	(3.8%)		—	0.0%
Amortization of Excess Deferred Income Taxes		**(27.9)**	**(3.5%)**		(29.0)	(4.4%)		(28.0)	(7.0%)
AFUDC Equity		**(6.5)**	**(0.8%)**		(15.0)	(2.3%)		(4.8)	(1.2%)
Nontaxable or Nondeductible Items									
Other		**0.8**	**0.1%**		0.4	0.1%		—	0.0%
Other adjustments		**1.9**	**0.2%**		0.3	0.0%		1.6	0.4%
Income Taxes		**142.1**	**18.1%**		106.3	16.2%		62.2	15.5%

The increase in tax expense of $35.8 million in 2025 versus 2024 was primarily due to higher pre-tax income and decrease in deferred tax amortization passed back to customers, offset by non-taxable AFUDC income.

The decrease in the Regulatory Liability, net of deferred tax amortization in 2025 versus 2024 was primarily due to the regulatory liability established for the renewable projects tax credits generated in 2025, net of TCJA excess deferred amortization.

The decrease in tax expense of $44.1 million in 2024 versus 2023 was primarily due to higher pre-tax income and decrease in deferred tax amortization passed back to customers, offset by non-taxable AFUDC income.

Net Deferred Income Tax Liability Components. Deferred income taxes result from temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The principal components of our net deferred tax liability were as follows.

At December 31, *(in millions)*		2025	2024
Deferred Tax Liabilities			
Accelerated depreciation and other property differences	**$**	**1,411.0** $	1,267.2
Partnership Basis differences		**89.0**	63.8
Other regulatory assets		**168.4**	111.3
Total Deferred Tax Liabilities	**$**	**1,668.4** $	1,442.3
Deferred Tax Assets			
Other regulatory liabilities and deferred investment tax credits (including TCJA)		**163.0**	131.9
Pensions and other postretirement/postemployment benefits		**51.8**	61.8
Net operating loss carryforward		**79.4**	114.3
Environmental liabilities		**9.4**	9.7
Other accrued liabilities		**26.7**	20.4
General business credits		**72.8**	6.0
Other, net		**3.7**	1.5
Total Deferred Tax Assets		**406.8**	345.6
Valuation Allowance	**$**	**—** $	—
Net Deferred Tax Assets	**$**	**406.8** $	345.6
Net Deferred Tax Liabilities	**$**	**1,261.6** $	1,096.7

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

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)	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 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year						(32,705)	(32,705)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income						51,615	51,615		
3	Preceding Quarter/Year to Date Changes in Fair Value									
4	Total (lines 2 and 3)						51,615	51,615	540,099,905	540,151,520
5	Balance of Account 219 at End of Preceding Quarter/Year						18,910	18,910		
6	Balance of Account 219 at Beginning of Current Year						18,910	18,910		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income						(21,167)	(21,167)		
8	Current Quarter/Year to Date Changes in Fair Value									
9	Total (lines 7 and 8)						(21,167)	(21,167)	624,559,281	624,538,114
10	Balance of Account 219 at End of Current Quarter/Year						(2,257)	(2,257)		

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

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)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	11,684,618,566	7,692,313,780	3,393,597,246				598,707,540
4	Property Under Capital Leases	150,056,864	113,195,139	34,070,551				2,791,174
5	Plant Purchased or Sold							
6	Completed Construction not Classified	6,829,757,595	4,898,124,144	1,896,060,632				35,572,819
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	18,664,433,025	12,703,633,063	5,323,728,429				637,071,533
9	Leased to Others							
10	Held for Future Use							
11	Construction Work in Progress	1,273,509,253	894,724,664	318,637,514				60,147,075
12	Acquisition Adjustments	27,522,227	27,522,227					
13	Total Utility Plant (8 thru 12)	19,965,464,505	13,625,879,954	5,642,365,943				697,218,608
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	5,889,136,698	3,984,363,028	1,473,613,012				431,160,658
15	Net Utility Plant (13 less 14)	14,076,327,807	9,641,516,926	4,168,752,931				266,057,950
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	5,480,330,485	3,984,160,987	1,416,199,222				79,970,276
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	408,806,213	202,041	57,413,790				351,190,382
22	Total in Service (18 thru 21)	5,889,136,698	3,984,363,028	1,473,613,012				431,160,658
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	Amortization of Plant Acquisition Adjustment							
33	Total Accum Prov (equals 14) (22,26,30,31,32)	5,889,136,698	3,984,363,028	1,473,613,012				431,160,658

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

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)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication					
3	Nuclear Materials					
4	Allowance for Funds Used during Construction					
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)					
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL (Total 8 & 9)					
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)					
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)					
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)					

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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 the 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) 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.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents	1,389					1,389
4	(303) Miscellaneous Intangible Plant	192,564,525	(2,185,032)			(190,379,493)	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	192,565,914	(2,185,032)			(190,379,493)	1,389
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	5,147,344	282,485				5,429,829
9	(311) Structures and Improvements	498,062,849	13,651,523	306,205			511,408,167
10	(312) Boiler Plant Equipment	1,380,259,689	19,035,525	8,168,634	3,703,163		1,394,829,743
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	355,647,706	2,853,494	180,297			358,320,903
13	(315) Accessory Electric Equipment	206,291,325	47,501				206,338,826
13.1	(315.1) Computer Hardware		2,576,581	4,581,188		5,283,319	3,278,712
13.2	(315.2) Computer Software		21,946			10,418,084	10,440,030
13.3	(315.3) Communication Equipment		182,422	781,428		2,871,735	2,272,729
14	(316) Misc. Power Plant Equipment	44,253,207	325,252	75,616			44,502,843
15	(317) Asset Retirement Costs for Steam Production	417,507,404	51,503,336	4,222,076	21,602,107		486,390,771
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,907,169,524	90,480,065	18,315,444	25,305,270	18,573,138	3,023,212,553
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						
19	(321) Structures and Improvements						
20	(322) Reactor Plant Equipment						
21	(323) Turbogenerator Units						
22	(324) Accessory Electric Equipment						
22.1	(324.1) Computer Hardware						
22.2	(324.2) Computer Software						
22.3	(324.3) Communication Equipment						
23	(325) Misc. Power Plant Equipment						
24	(326) Asset Retirement Costs for Nuclear Production						
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)						
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	23,137					23,137
28	(331) Structures and Improvements	11,545,149	636,285	73,727			12,107,707
29	(332) Reservoirs, Dams, and Waterways	63,253,156	2,263,714				65,516,870

30	(333) Water Wheels, Turbines, and Generators	14,248,522	1,057,126	303,775			15,001,873
31	(334) Accessory Electric Equipment	2,435,409	366,789	77,027			2,725,171
31.1	(334.1) Computer Hardware						
31.2	(334.2) Computer Software					3,996,621	3,996,621
31.3	(334.3) Communication Equipment		384,321			5,022,248	5,406,569
32	(335) Misc. Power Plant Equipment	1,348,335	368,553				1,716,888
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)	92,853,708	5,076,788	454,529		9,018,869	106,494,836
35.1	D. Solar Production Plant						
35.2	(338.1) Land and Land Rights		710,709				710,709
35.3	(338.2) Structures and Improvements		243,587,375			53,683,060	297,270,435
35.5	(338.4) Solar Panels		811,685,624			231,858,946	1,043,544,570
35.6	(338.5) Collector System		285,962,317				285,962,317
35.7	(338.6) Generator Step-up Transformers (GSU)		20,551,973				20,551,973
35.8	(338.7) Inverters		118,052,882			236,494	118,289,376
35.9	(338.8) Other Accessory Electrical Equipment		65,572,406			35,237,283	100,809,689
35.10	(338.9) Computer Hardware		3,868,369			866,240	4,734,609
35.11	(338.10) Computer Software		2,027,623			7,853,145	9,880,768
35.12	(338.11) Communication Equipment		851,472			319,700	1,171,172
35.13	(338.12) Miscellaneous Power Plant Equipment		969,420				969,420
35.14	(338.13) Asset Retirement Costs for Solar Production		35,431,415			20,480,799	55,912,214
35.15	TOTAL Solar Production Plant (Enter Total of lines 35.2 thru 35.14)		1,589,271,585			350,535,667	1,939,807,252
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					3,066,516	3,066,516
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)					3,066,516	3,066,516
35.33	F. Other Renewable Production Plant						
35.34	(339.1) Land and Land Rights						
35.35	(339.2) Structures and Improvements						
35.36	(339.3) Fuel Holders						
35.37	(339.4) Boilers						
35.39	(339.6) Generators						
35.41	(339.8) Other Accessory Electrical Equipment						
35.42	(339.9) Computer Hardware						
35.43	(339.10) Computer Software						

35.44	(339.11) Communication Equipment						
35.45	(339.12) Miscellaneous Power Plant Equipment						
35.46	(339.13) Asset Retirement Costs for Other Renewable Production						
35.47	TOTAL Other Renewable Production Plant (Enter Total of lines 35.34 thru 35.46)						
36	G. Other Production Plant						
37	(340) Land and Land Rights	1,031,346	8				1,031,354
38	(341) Structures and Improvements	71,278,717	3,221,365	240,386		(56,076,595)	18,183,101
39	(342) Fuel Holders, Products, and Accessories	11,820,034					11,820,034
40	(343) Prime Movers	153,563,749	609,079	167,951			154,004,877
41	(344) Generators	333,532,673				(286,737,242)	46,795,431
42	(345) Accessory Electric Equipment	92,506,864				(40,753,126)	51,753,738
42.1	(345.1) Computer Hardware		7,027,115				7,027,115
42.2	(345.2) Computer Software		16,396,601			31,217,001	47,613,602
42.3	(345.3) Communication Equipment						
43	(346) Misc. Power Plant Equipment	5,804,509	(4)				5,804,505
44	(347) Asset Retirement Costs for Other Production	53,495,974	(31,097,160)			(22,398,814)	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	723,033,866	(3,842,996)	408,337		(374,748,776)	344,033,757
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, 35.15, 35.32, 35.47, and 45)	3,723,057,098	1,680,985,442	19,178,310	25,305,270	6,445,414	5,416,614,914
47	3. Transmission Plant						
48	(350) Land and Land Rights	87,429,080	6,178,936				93,608,016
48.2	(351.1) Computer Hardware		338,329	151,338		3,259,818	3,446,809
48.3	(351.2) Computer Software		15			1,261,715	1,261,730
48.4	(351.3) Communication Equipment		38,853,540	59,990		48,285,841	87,079,391
49	(352) Structures and Improvements	125,613,326	30,435,935	387,426			155,661,835
50	(353) Station Equipment	1,014,924,222	113,467,010	3,300,847			1,125,090,385
51	(354) Towers and Fixtures	253,322,790	9,069,295	19,712	(2,092,715)		260,279,658
52	(355) Poles and Fixtures	589,258,707	76,584,403	1,089,248	1,269,555		666,023,417
53	(356) Overhead Conductors and Devices	350,544,881	59,930,446	380,266	823,154		410,918,215
54	(357) Underground Conduit	96,026		7,772			88,254
55	(358) Underground Conductors and Devices	4,132,370	(311)				4,132,059
56	(359) Roads and Trails	1,129					1,129
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,425,322,531	334,857,598	5,396,599	(6)	52,807,374	2,807,590,898
59	4. Distribution Plant						
60	(360) Land and Land Rights	10,821,644	5,442,750				16,264,394
61	(361) Structures and Improvements	21,940,825	9,636,427	145,778			31,431,474
62	(362) Station Equipment	652,598,820	79,960,539	3,923,586		1,346,734	729,982,507
63.1	(363.1) Computer Hardware		6,426,179			604,894	7,031,073
63.2	(363.2) Computer Software		26,504,706			19,059,948	45,564,654
63.3	(363.3) Communication Equipment		34,470,508	466		27,463,342	61,933,384
64	(364) Poles, Towers, and Fixtures	721,093,321	109,895,351	1,234,757		(1,346,734)	828,407,181
65	(365) Overhead Conductors and Devices	436,697,498	45,453,383	81,002			482,069,879
66	(366) Underground Conduit	6,195,558	46,647	1,065,281			5,176,924
67	(367) Underground Conductors and Devices	625,623,693	78,958,683	434,440			704,147,936
68	(368) Line Transformers	392,995,713	58,068,251	95,145			450,968,819
69	(369) Services	335,892,318	28,291,403	350,184			363,833,537
70	(370) Meters	88,925,862	65,428,424	25,648,449			128,705,837
71	(371) Installations on Customer Premises	11,017,032	812,527	173,867			11,655,692
72	(372) Leased Property on Customer Premises						

73	(373) Street Lighting and Signal Systems	62,172,520	6,750,550	259,192			68,663,878
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,365,974,804	556,146,328	33,412,147		47,128,184	3,935,837,169
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
84.1	6. ENERGY STORAGE PLANT						
84.2	(387.1) Land and Land Rights						
84.3	(387.2) Structures and Improvements		4,385,207			2,393,535	6,778,742
84.4	(387.3) Energy Storage Equipment		87,106,729			54,878,296	141,985,025
84.6	(387.5) Collector System		4,594,807				4,594,807
84.7	(387.6) Generator Step-up Transformers (GSU)						
84.8	(387.7) Inverters		8,620,871				8,620,871
84.9	(387.8) Computer Hardware		775,307			607,598	1,382,905
84.10	(387.9) Computer Software		269,411			2,222,421	2,491,832
84.11	(387.10) Communication Equipment		40,412			32,133	72,545
84.12	(387.11) Miscellaneous Energy Storage Equipment		1,436,741			5,279,350	6,716,091
84.13	(387.12) Asset Retirement Costs for Energy Storage		962,565			1,918,015	2,880,580
84.14	TOTAL Energy Storage Plant (Total lines 84.2 thru 84.13)		108,192,050			67,331,348	175,523,398
85	7. General Plant						
86	(389) Land and Land Rights	122,880					122,880
87	(390) Structures and Improvements	31,875,667	2,887,122	320,217			34,442,572
88	(391) Office Furniture and Equipment	22,644,084	197,398	282,423		(17,721,623)	4,837,436
89	(392) Transportation Equipment	2,682,224	1,242,006				3,924,230
90	(393) Stores Equipment	839,834		107,795			732,039
91	(394) Tools, Shop and Garage Equipment	32,774,951	1,264,911	567,144			33,472,718
92	(395) Laboratory Equipment	5,854,176	333,582	723,341			5,464,417
93	(396) Power Operated Equipment	5,253,617	495,354	9,879			5,739,092
94	(397.1) Computer Hardware		[(a)]337,201	43,683		7,099,752	7,393,270
94.1	(397.2) Computer Software		20,911,547			111,284,042	132,195,589
94.2	(397.3) Communication Equipment		117,118	73,076		21,324,638	21,368,680
95	(398) Miscellaneous Equipment	5,817,879	1,143,944	18,708			6,943,115
96	SUBTOTAL (Enter Total of lines 86 thru 95)	213,184,949	28,930,183	2,146,266		16,667,172	256,636,038
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant						
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	213,184,949	28,930,183	2,146,266		16,667,172	256,636,038
100	TOTAL (Accounts 101 and 106)	9,920,105,296	2,706,926,569	60,133,322	25,305,264	(1)	12,592,203,806
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)	9,920,105,296	2,706,926,569	60,133,322	25,305,264	(1)	12,592,203,806

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Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: ComputerHardwareGeneralPlantAdditions
In 2024, Account 397 had an ending balance of $105,319,637. Due to FERC 898 changes, this line is not presentable in Form 1. The amount in this account has been transferred to its sub accounts, leaving an ending balance in 2025 of $0.

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ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
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47	TOTAL		

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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:			
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21	Other Property:			
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47	TOTAL			

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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	ELECTRIC CONTROL CENTER (ECC) MODER	60,985,696
2	345kV Synchronous Condenser	56,560,730
3	RMS Gas Peaker CT Common	42,857,659
4	TDSIC- Menges Ditch Lines for New S	38,899,313
5	TDSIC- Menges Ditch New Substation	37,219,297
6	PE-MISO LRTP-Reynolds Morrison Dtch	33,930,158
7	RMS Gas Peaker - Indus. Frame	32,377,845
8	RMS Gas Peaker Electric Intercon.	25,046,792
9	RMS Gas Peaker Aeroderivative 1	23,530,301
10	RMS Gas Peaker Aeroderivative 2	23,472,238
11	RMS Gas Peaker Aeroderivative 3	23,448,910
12	PE-MISO LRTP-Reynold-Goodlnd-13857	14,468,719
13	Prelim MISO LRTP Reynolds 345XX	14,327,629
14	Oakdale Head Gate & Stop Log	11,805,100
15	Minor Line Improvements	11,373,638
16	TDSIC- Cir 6958 Thayer Cir Rebuild	8,476,824
17	PE-MISO LRTP-Cr 138105-Morrison Dtc	7,676,987
18	Norway Floodgate Replacement Projec	7,673,177
19	TDSIC- Oakdale Sub Relay, Breaker U	7,262,219
20	TDSIC- Knox Sub Transf & Recl Repla	7,057,989
21	PE-MISO LRTP-Cr345XX-Burr Oak Lsbrg	6,690,694
22	TDSIC- AMI ONMS 2.6 Upgrade	6,324,109
23	TDSIC- Fisher 12-294 Cir Rebuild	5,744,673
24	TDSIC- Demotte Sub Transformer Upgr	5,628,024
25	ER CAP 16A Turbine Outage 2025	5,598,075
26	TDSIC- Babcock Sub Lattice Tower	5,539,443
27	TDSIC- Woodland Park Switchgear Upg	5,184,497
28	TDSIC- Lowell Sub Repl #1 Transf	5,051,818
29	PE-MISO LRTP-Cr 345XX-Leesbrg Hiple	5,006,001
30	TDSIC- CR CDC Cir 12-252 Liberty Pk	4,903,506
31	Oakdale Xfr and Sub Relocat	4,856,753
32	TDSIC- Schrader Ditch New 69kV Line	4,755,523
33	TDSIC- Hager Sub 2nd 69 Src Sub & C	4,408,408
34	2025 SCGS-Steam Turbine Blade Rplcm	4,149,152
35	SCGS Hot Reheat Bypass Vlv & Piping	3,966,532
36	TDSIC- AMI Electric Metering 2026	3,911,097
37	TDSIC- Morrison Ditch Sub Lattice T	3,895,772
38	TDSIC- Pine Creek Sub Volt Reg Mono	3,825,113
39	TDSIC- Menges Ditch Communication	3,805,179
40	TDSIC- CR Cir 12-565 Johnson Rebuil	3,744,366
41	TDSIC- Dune Acres Sub Lattice Tower	3,707,276
42	TDSIC- Medaryville Sub Repl 69/12 T	3,701,401
43	TDSIC- Broadway Sub Relocation & Re	3,591,193
44	Prelim-NCS-DX Hammond - Sub & Comm	3,484,490
45	LEESBURG SUBSTATION IPP	3,335,952
46	PRELIM-NCS-NICTD-Miller Substation	3,297,723

47	Prelim-MISO LRTP-Burr Oak Substatio		3,240,267
48	Other Minor Line Improvements		3,131,822
49	Dunns Bridge 2 - Solar Grazing		3,113,547
50	TDSIC- Midway Sub #1 Transform Repl		3,020,052
51	TDSIC- New Chesterton Sub		3,019,046
52	TDSIC- Kentland Sub Rebuild		2,952,357
53	TDSIC- UGC RC Cir 12-145 Crown Pt		2,906,549
54	TDSIC- CR CDC Cir 12-254 Liberty Pk		2,764,962
55	U18 Major LP Turbine Outage		2,676,344
56	TDSIC- PRP 2025 POLE INSPECT & TREA		2,665,327
57	RMS -16A&B, Serv Wtr, Hydrog		2,663,163
58	TDSIC- WC ZT Hager Cir 12-816 CP		2,613,844
59	PINES SUBSTATION		2,608,764
60	Minor Outage Restoration		2,538,299
61	TDSIC- Hanna Sub Voltage Regs Monop		2,494,953
62	TDSIC- Hager 2nd 69kV Source Primar		2,440,541
63	Prelim MISO LRTP Circuit #13871		2,433,277
64	TDSIC- Schrader Ditch New Sub		2,136,727
65	TDSIC- SouthLake Switchgear Upgrade		2,084,235
66	Minor New Business		2,079,326
67	TDSIC- Parr Sub Monopole Comm Upgra		2,041,660
68	Prelim MISO LRPT F. G. Hiple Sub		2,012,951
69	MCGS #11 XFR REPLACEMENT		2,000,833
70	TDSIC- PRPD JW Cir 34-124 T57 Mich		1,992,412
71	NB-OZINGA 3478/3450 UPGRADE-EAST CH		1,970,297
72	2025 SCGS Valve Replacement ND		1,943,083
73	AAR FERC Order 881		1,934,690
74	PRELIM-Roxana Cir #13808 Upgrade		1,931,993
75	TDSIC- Cir 12-194 Chesterton Cir Re		1,899,182
76	Prelim MISO LRTP Morrison Ditch		1,875,783
77	Purchase Of Line Transformers		1,846,103
78	TDSIC- Burns Ditch Sub Latt Twr Com		1,817,990
79	2025 U12 Catalyst Layer #3 Rep'l		1,802,363
80	Prelim MISO LRTP Circuit 345XX		1,753,623
81	TDSIC- Nealon Drive Sub New Transfo		1,739,659
82	TDSIC- Griffith #1 Transf & Switchg		1,729,968
83	TDSIC- AMI Electric MDMS		1,688,458
84	TDSIC- Miller Sub 13822 Breaker Upg		1,670,153
85	PE-PIE-Roundabout-US231 and Parrish		1,642,820
86	Prelim-NCS-DX Hammond Sub-Line		1,632,804
87	TDSIC- Dekalb Sub #1 Transf Upgrade		1,613,830
88	NBE - CIR 3403 - YAB DEVELOPMENT -		1,599,358
89	TDSIC- Circuit Rebuild - Thayer 695		1,580,788
90	TDSIC- Goshen Junc Sub Latt Twr Com		1,565,658
91	PRE-MISO LRTP-Cr 13847-Magnetation		1,538,089
92	TDSIC- North Robbins New Substation		1,530,989
93	TDSIC- North Robbins 12 & 69 Line E		1,525,973
94	Burns Ditch Substation Security Ins		1,518,406
95	TDSIC- Chesterton Line Ext New Sub		1,495,412
96	TDSIC- Mitchell Sub Lattice Twr Com		1,482,908
97	NBEJ-KAH-GATES OF ST JOHN UNIT 29-3		1,482,314
98	TDSIC- Cir 12-149 McCool Capacity U		1,468,205
99	2025 Non-Project IT hardware - Cybe		1,457,287

100	TDSIC- UCR RLC Cir 12-859 Bingo Lak	1,447,578
101	Prelim MISO LRTP - Reynolds Sub	1,431,453
102	TDSIC-AMI Electric MDMS License Fee	1,424,331
103	TDSIC- South Valpo Lattice Twr Comm	1,423,742
104	Starke to Knox 6905 Extension	1,392,469
105	TDSIC- Oakdale Hydro Line Work	1,376,368
106	TDSIC- Flint Lake Sub Monopole Comm	1,347,410
107	TDSIC- Robertsdale Sub Switchgear U	1,325,486
108	PIE-Wisconsin St Bridge Reconstruct	1,322,531
109	TDSIC- RM Schahfer Sub Lattice Twr	1,318,639
110	TDSIC- Deer Run Sub Volt Reg Monopo	1,295,179
111	TDSIC- WC Cir ZT 12-351 Crown Point	1,264,413
112	TDSIC- Northeast Sub Lattice Twr Co	1,256,073
113	TDSIC- Praxair BH Sub Monopole Comm	1,249,758
114	TDSIC- Hebron Sub 2 Transf Rpl Comm	1,247,211
115	Circuit 12-657 UG to OH	1,241,499
116	Electric OT: EMS Server Refresh	1,236,657
117	TDSIC- Burr Oak Sub Lattice Twr Com	1,235,917
118	TDSIC- Liable Sub Replace Switchgea	1,223,836
119	TDSIC- RMSGS Sub Bus Upgrades	1,219,757
120	DELAWARE #1 XFR REPLACEMENT	1,218,530
121	TDSIC- Lagrange Sub Lattice Twr Com	1,198,131
122	TDSIC- Hendricks to USS Stock Fiber	1,189,808
123	TDSIC- Pine Manor Sub UG Fiber Opti	1,174,172
124	TDSIC-PRP-T-DVG-CKT 6943 PK 7/7,202	1,120,889
125	Prelim MISO LRTP Leesburg Sub	1,117,731
126	2025 Generation Capital Tools ND	1,116,201
127	TDSIC- Viper Recloser Goshen Pk12	1,111,377
128	MONOGRAM FOODS NEW CUSTOMER SUBSTAT	1,049,437
129	TDISC-UCR-DJH-12-654 NOVAK RD,SCHER	1,042,569
130	IT Renewables Technology (2025-2026	1,038,452
131	TDSIC- Viper Recloser Goshen Pk15	1,032,204
132	Other Individual Projects less than $1 Million	138,107,421
43	Total	894,724,664

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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 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

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)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	3,686,148,082	3,686,148,082		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	373,298,952	373,298,952		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	679,166	679,166		
7	Other Clearing Accounts	58,942	[a]58,942		
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):				
9.2	Other: Regulatory Assets	6,812,154	6,812,154		
9.3	Other: Capital Leases	3,289,793	3,289,793		
9.4	Other: Asset Retirement Obligations	(35,567,365)	(35,567,365)		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	348,571,642	348,571,642		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(55,911,246)	(55,911,246)		
13	Cost of Removal	(12,560,552)	(12,560,552)		
14	Salvage (Credit)	12,847	12,847		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(68,458,951)	(68,458,951)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):				
17.2	Retirement Work in Progress	(60,077,548)	(60,077,548)		
18	Book Cost or Asset Retirement Costs Retired	77,977,762	77,977,762		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,984,160,987	3,984,160,987		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,676,551,243	1,676,551,243		
21	Nuclear Production				
22	Hydraulic Production-Conventional	28,974,715	28,974,715		
23	Hydraulic Production-Pumped Storage				
23.1	Solar Production	48,402,037	48,402,037		
23.2	Wind Production	1,116,310	1,116,310		
23.3	Other Renewable Production				
24	Other Production	183,745,749	183,745,749		
25	Transmission	710,373,669	710,373,669		
26	Distribution	1,236,100,794	1,236,100,794		
27	Regional Transmission and Market Operation				
27.1	Energy Storage	6,438,065	6,438,065		
28	General	92,458,405	92,458,405		
29	TOTAL (Enter Total of lines 20 thru 28)	3,984,160,987	3,984,160,987		

FOOTNOTE DATA

(a) Concept: OtherClearingAccounts
Mobile Fuel Expenses = $2,389,765Unit Train Clearing = $58,527

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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different 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.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	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)
1	Common Stock	10/29/2009		1,000			1,000	
2	Additional Paid-In Capital	10/23/2009		29,999,000			29,999,000	
3	Undistributed Earnings			333,154	(18,468,896)		(18,135,742)	
4	Tax Savings Allocation			1,067,383			1,067,383	
42	Total Cost of Account 123.1 $		Total	31,400,537	(18,468,896)		12,931,641	

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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)	30,296,797	7,244,233	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	5,903,307	1,277,096	Electric
3	Residuals and Extracted Products (Account 153)			Electric
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	[a]80,825,694	91,926,174	T&D
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	51,885,565	59,011,449	Electric
8	Transmission Plant (Estimated)	12,204,158	13,880,258	Electric
9	Distribution Plant (Estimated)	8,002,267	9,101,286	Electric and Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
10.1	Energy Storage Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[b]2,707,885	[c]3,079,782	Electric and Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	155,625,569	176,998,949	
13	Merchandise (Account 155)	8,083	8,498	Gas
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)			Common
17				
18				
19				
20	TOTAL Materials and Supplies	191,833,756	185,528,776	

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesConstruction

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

Assigned to Construction (Estimated)

		2025
Transmission Plant (Estimated)	$	55,521,030
Distribution Plant (Estimated)	$	36,405,144
	$	91,926,174
		2024
Transmission Plant (Estimated)	$	48,816,629
Distribution Plant (Estimated)	$	32,009,066
	$	80,825,695

(b) Concept: PlantMaterialsAndOperatingSuppliesOther

Miscellaneous

(c) Concept: PlantMaterialsAndOperatingSuppliesOther

Miscellaneous

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Allowances and Environmental Credits (Accounts 158.1, 158.2, 158.3, and 158.4)

1. Report below the details related to allowances and environmental credits. Additional information about the type of allowances/environmental credits required by other regulatory bodies can be disclosed within the footnote data.
2. Report all acquisitions of allowances and environmental credits at cost.
3. Report allowances and environmental credits in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances and environmental credits transactions by the period they are first eligible for use: the current year's allowances and environmental credits in columns (b)-(c), allowances and environmental credits for the three succeeding years in columns (d)-(i), starting with the following year, and allowances and environmental credits for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 authoritative agency issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by an authoritative agency. Report on Line 39 the authoritative agency's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the authoritative agency's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances and environmental credits acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances and environmental credits disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance and environmental credits sales.

Line No.	Allowances and Environmental Credits Inventory (Accounts 158.1, 158.3, and 158.4) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	654,719		698,281		785,320		836,027		886,733		3,861,080	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	87,040		87,040		50,706		50,706		50,706		326,198	
5	Returned by authoritative agency	669										669	
6													
7													
8	Purchases/Transfers In:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509, 555.2, and 555.3	2,330										2,330	
19	Other:												
20	Allowances Used												
20.1	Excess Surrender to EPA	41,818										41,818	
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	698,280		785,321		836,026		886,733		937,439		4,143,799	
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year	1,449										1,449	

37	Add: Withheld by authoritative agency												
38	Deduct: Returned by authoritative agency												
39	Cost of Sales												
40	Balance-End of Year	1,449										1,449	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

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EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
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						
20	TOTAL					

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

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	J607262 - MISO Study J1646	77	561.6	77	561.6
3	J607263 - MISO Study J1684	256	561.6	256	561.6
4	J607271 - MISO Study DPP-2022	264	561.6	264	561.6
5	J607273 - MISO short circuit study J1861, 2044, 2045, 2048, 2187, 2213, 2215, 2226	14,400	561.6	14,400	561.6
6	J607274 - MISO Study J2187 CPP2021-Central Interconnection Facilities	43	561.6	4,212	561.6
7	J607275 - MISO Study J2213 CPP2021-Central Interconnection Facilities	24,111	561.6	24,111	561.6
8	J607276 - MISO Study J2215 CPP2021-Central Interconnection Facilities	57,839	561.6	57,839	561.6
9	J607277 - MISO Study J2226 CPP2021-Central Interconnection Facilities	57,798	561.6	57,798	561.6
10	J607278 - DPP-2021-Central Interconnection Customer Interconnection Facilities	105,341	561.6	105,341	561.6
11	J607279 - DPP-2021-Central Interconnection Customer Interconnection Facilities	84,759	561.6	116,434	561.6
12	J607280 - DPP-2021-Central Interconnection Customer Interconnection Facilities	59,107	561.6	90,782	561.6
13	J607281 - DPP-2021-Central Interconnection Customer Interconnection Facilities	46,713	561.6	71,388	561.6
14	J607282 - DPP-2021-Central Interconnection Customer Interconnection Facilities	76,486	561.6	112,976	561.6
15	J607283 - DPP-2020-Cycle-Central J1802 & J1724	185,112	561.6	185,112	561.6
16	J607284 - DPP-2022-Central Interconnection Customer Interconnection Facilities-Reynolds to Burr Oak 34528 J2353, J2657, J2663	160,100	561.6	56,046	561.6
17	J607285 - DPP-2022-Central Interconnection Customer Interconnection Facilities-South of 345KV Yard at Reynolds J2496	150,075	561.6	52,546	561.6
18	J607286 - DPP-2022-Central Interconnection Customer Interconnection Facilities-Reynolds to Burr Oak 34528 J2846	160,077	561.6	56,045	561.6
19	J607287 - DPP-2022-Central Interconnection Customer Interconnection Facilities-Reynolds to Burr Oak 34528 J2847	160,077	561.6	56,046	561.6
20	J607288 - DPP-2022-Central Interconnection Customer Interconnection Facilities-Reynolds to Burr Oak 34528 J2849	160,076	561.6	56,046	561.6
21	J607289 - DPP-2022-Central Interconnection Customer Interconnection Facilities-Cir. 13896 Stillwell to Plymouth J3207	112,000	561.6	56,000	561.6
20	Total	1,614,711		1,173,719	
21	**Generation Studies**				
39	Total				
40	Grand Total	1,614,711		1,173,719	

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OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During Quarter/Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	GAS					
2	TDSIC Gas Tracker 80 - Order 45330	6,538,328	1,682,478	403/408/421/431/880	1,352,647	6,868,159
3	TDSIC Gas Deferred 20 - Order 44403/45330/44988	10,018,503	2,055,217	403/408/421/431/880	5,041,389	7,032,331
4	Gas Rate Case Costs - Order 44988/45621	2,253,565	725,159	923.00	1,275,101	1,703,623
5	FMCA Rider Deferred 20 - Order 45007/45660	13,656,832	38,554,333	107/108	39,832,051	12,379,114
6	Other Miscellaneous - Order 44988			931.00		
7	Weather Normalization Gas Adjustment - Order 45967	12,650,984	16,445,561		18,669,141	10,427,404
8	WAM Gas Deferral - Order 46025	3,500,532	6,740,138		2,158,743	8,081,927
9	Underrecovered Gas Costs - Order 43629		13,537,795			13,537,795
10	Gas DSM - Order 44001		1,994,645			1,994,645
11	ELECTRIC					
12	Electric Rate Case Costs - Order 44688/45159/45772	3,960,024	1,873,506	923.00	2,251,194	3,582,336
13	Electric Vehicle Deferral - Order 44688			923.00		
14	FMCA Rider Deferred 80	1		403/408/421/431/548		1
15	FMCA Rider Deferred 20 - Order 44688/45772	1,827,008	98,844	403/408/421/431/548/560	973,126	952,726
16	TDSIC Deferred - Order 45557	19,620,266	79,487,317	403/408/421/431	91,516,425	7,591,158
17	TDSIC Deferred 20 - Order 44688/44733/45772	26,654,910	32,416,949	403/408/421/431/588	28,248,708	30,823,151
18	Mercury Air Toxins Deferred 20 - Order 44688	96,319		403/421/431/548	48,168	48,151
19	EERM O&M Deferral - Order 45159/45772	15,170,911	23,026,198		17,677,409	20,519,700
20	CIS Rider 677 - Order 44688/45159	15,549,134	5,492,094	442.00	4,428,815	16,612,413
21	Fuel Surcharge Litigation - Order 38706-FAC-125	5,571,646	185,563		25,500	5,731,709
22	Schahfer Generation - Order 45159	536,051,933		407.00	56,426,519	479,625,414
23	Rosewater Wind Joint Venture - Order 45194/45772	91,624,284	5,751,430	407/421/431	8,956,944	88,418,770
24	Indiana Crossroads Wind Joint Venture - Order 45310/45772	302,320,997	11,566,773	407/421/431	22,143,601	291,744,169
25	Indiana Crossroads Solar Joint Venture - Order 45524/45772	194,928,275	9,339,925	407/421/431	16,159,573	188,108,627
26	Dunns I Solar Joint Venture - Order 45462/45772	212,012,393	14,821,457	407/421/431	22,238,800	204,595,050
27	Dunns II Solar Joint Venture - Order 45462	3,399,477	46,851,845		17,022,976	33,228,346
28	Calvary Solar Joint Venture - Order 45462	27,169,922	40,104,257		22,595,583	44,678,596
29	Fairbanks Solar Joint Venture - Order 45511	1,131,947	4,805,739		1,094,989	4,842,697
30	RA Rider Deferral - Order 44155	3,099,735	6,391,840		8,956,842	534,733
31	Gibson Solar Joint Venture - Order 45926	104,637	808,180		737,755	175,062
32	WAM Electrict Deferral - Order 46025	18,039,405	11,221,474		3,832,279	25,428,600
33	RTO Rider Deferral - Order 44156	2,471,563			2,471,563	
34	GCT Rider 576		373,891		305,240	68,651
35	Green Power - Order 44198		3,533,875		3,501,448	32,427
36	OTHER					
37	FAS 133 Current - Order 38706/43629	4,350,708	5,097,246	175/232	4,350,708	5,097,246
38	FAS 133 Non-Current - Order 38706/43629	1,047,931	4,277,884	175,232.00	1,047,931	4,277,884
39	FAS 158-OPEB - Order 45159/45621	23,518,227	10,261,996	228.00	26,767,744	7,012,479
40	FAS 158-Pension - Order 45159/45621	354,985,638	42,001	228/926	21,015,460	334,012,179
41	Federal Income Tax - Order 45159/45621	12,074,341	7,787,142		6,143,012	13,718,471

42	COVID Costs - Order 45377/45772	3,044,024	2,215,197	904/921/450	3,322,795	1,936,426
44	TOTAL	1,928,444,400	409,567,949		462,590,179	1,875,422,170

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

MISCELLANEOUS DEFFERED 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 (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Credits Account Charged (d)	CREDITS Credits Amount (e)	Balance at End of Year (f)
1	Goodwill	17,753,079				17,753,079
2	Materials Holding	835,500	638,506	107/506/588/880	495,265	978,741
3	Gas Hedging Gain/Loss	(87,220)		807	111,348	(198,568)
4	Pension Trust Asset	53,965,901	10,830,862	182 / 926		64,796,763
5	Legal Accruals	25,000		232	14,000	11,000
6	TDSIC			107	815,428	(815,428)
7	Data Center Development		8,443,513	107		8,443,513
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	72,492,260				90,969,100

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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		161,057,749	245,396,788
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	161,057,749	245,396,788
9	Gas		
10		159,280,802	119,164,520
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	159,280,802	119,164,520
17.1	Other (Specify)		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	320,338,551	364,561,308

Notes

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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.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. 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 purpose of pledge.

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)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	NIPSCO converted from a corporation to a limited liability company on 2/16/2018.					859,487,917				
4	Total					859,487,917				
5	Preferred Stock (Account 204)									
6										
7										
8										
9	Total									

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Other Paid-in Capital

1. 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 a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
Gain or 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.
Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	12,545,234
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	12,545,234
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	1,319,195,925
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	1,297,411,935
16	Ending Balance Amount	2,616,607,860
17	**Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	2,629,153,094

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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	NIPSCO converted from a corporation to a limited liability company on 2/16/2018.	469,622
22	TOTAL	469,622

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

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

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. 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, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, 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) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	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)
1	Bonds (Account 221)												
2													
3													
4													
5	Subtotal												
6	Reacquired Bonds (Account 222)												
7													
8													
9													
10	Subtotal												
11	Advances from Associated Companies (Account 223)												
12	Long Term Note, 5.985%		75,000,000					09/19/2005	09/18/2025	09/19/2005	09/18/2025		3,197,466
13	Long Term Note, 6.410%		120,000,000					12/04/2009	12/04/2029	12/04/2009	12/04/2029	120,000,000	7,692,000
14	Long Term Note, 4.530%		55,000,000					12/19/2012	12/21/2037	12/19/2012	12/21/2037	55,000,000	2,491,500
15	Long Term Note, 4.830%		95,000,000					12/19/2012	12/19/2042	12/19/2012	12/19/2042	95,000,000	4,588,500
16	Long Term Note, 5.170%		89,000,000					07/24/2013	07/26/2038	07/24/2013	07/26/2038	89,000,000	4,601,300
17	Long Term Note, 5.430%		95,000,000					07/24/2013	07/24/2043	07/24/2013	07/24/2043	95,000,000	5,158,500
18	Long Term Note, 4.990%		66,000,000					02/13/2014	02/15/2044	02/13/2014	02/15/2044	66,000,000	3,293,400
19	Long Term Note, 4.350%		82,000,000					12/18/2014	12/16/2044	12/18/2014	12/16/2044	82,000,000	3,567,000
20	Long Term Note, 4.55%		93,750,000					06/26/2015	06/26/2035	06/26/2015	06/26/2035	93,750,000	4,265,625
21	Long Term Note, 4.99%		93,750,000					06/26/2015	06/26/2045	06/26/2015	06/26/2045	93,750,000	4,678,125
22	Long Term Note, 4.7006%		91,000,000					12/30/2015	12/30/2045	12/30/2015	12/30/2045	91,000,000	4,277,546
23	Long Term Note, 4.3640%		210,000,000					12/30/2016	12/30/2046	12/30/2016	12/30/2046	210,000,000	9,164,400
24	Long Term Note, 4.1611%		40,000,000					06/30/2017	06/30/2047	06/30/2017	06/30/2047	40,000,000	1,664,440
25	Long Term Note, 4.1123%		162,500,000					09/29/2017	09/29/2047	09/29/2017	09/29/2047	162,500,000	6,682,487
26	Long Term Note. 4.530%		450,000,000					06/29/2018	06/29/2048	06/29/2018	06/29/2048	450,000,000	20,375,550
27	Long Term Note. 3.568%		150,000,000					09/30/2019	09/30/2049	09/30/2019	09/30/2049	150,000,000	5,351,850

28	Long Term Note, 3.174%		208,000,000					06/30/2020	06/30/2050	06/30/2020	06/30/2050	208,000,000	6,602,336
29	Long Term Note, 3.272%		175,000,000					06/30/2021	06/30/2051	06/30/2021	06/30/2051	175,000,000	5,726,000
30	Long Term Note, 5.081%		225,000,000					06/30/2022	06/30/2052	06/30/2022	06/30/2052	225,000,000	11,431,800
31	Long Term Note 5.650%		210,000,000					12/30/2022	12/30/2052	12/30/2022	12/30/2052	210,000,000	11,864,580
32	Long Term Note, 5.317%		250,000,000					03/31/2023	03/31/2053	03/31/2023	03/31/2053	250,000,000	13,292,000
33	Long Term Note, 5.298%		315,000,000					04/28/2023	04/28/2053	04/28/2023	04/28/2053	315,000,000	16,689,960
34	Long Term Note, 5.432%		300,000,000					12/15/2023	12/15/2053	12/15/2023	12/15/2053	300,000,000	16,294,500
35	Long Term Note, 5.672%		175,000,000					03/28/2024	03/28/2054	03/28/2024	03/28/2054	175,000,000	9,926,175
36	Long Term Note, 5.912%		250,000,000					06/28/2024	06/28/2054	06/28/2024	06/28/2054	250,000,000	14,781,000
37	Long Term Note, 5.376%		100,000,000					09/30/2024	09/30/2054	09/30/2024	09/30/2054	100,000,000	5,376,200
38	Long Term Note, 5.919%		200,000,000					12/31/2024	12/31/2054	12/31/2024	12/31/2054	200,000,000	11,869,831
39	Long Term Note, 5.844%		525,000,000					03/31/2025	03/31/2055	03/31/2025	03/31/2055	525,000,000	23,200,276
40	Long Term Note, 5.903%		100,000,000					06/30/2025	06/30/2055	06/30/2025	06/30/2055	100,000,000	2,991,779
41	Long Term Note, 5.715%		100,000,000					09/30/2025	09/30/2055	09/30/2025	09/30/2055	100,000,000	1,456,025
42	Long Term Note, 5.823%		50,000,000					12/31/2025	12/31/2055	12/31/2025	12/31/2055	50,000,000	
43	Subtotal		5,151,000,000									5,076,000,000	242,552,151
44	Other Long Term Debt (Account 224)												
45	Medium Term Notes, Series E, Variable %		58,000,000					06/06/1997	08/04/2027	06/06/1997	08/04/2027	58,000,000	4,433,700
46	Subtotal		58,000,000									58,000,000	4,433,700
33	TOTAL												

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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 filed, 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)	624,559,281
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	SFAS133 - Book Hedging Income/Loss	7,546,164
6	Federal Net Operating Loss Carryforward	
7	Total	7,546,164
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal Current Income Tax Expense	7,014,361
11	Federal Deferred Income Tax Expense	111,002,611
12	State Current Income Tax Expense	2,108,568
13	State Deferred Income Tax Expense	21,960,258
14	Business Meals & Entert	1,505,226
15	Employee Stock Purchase	437,153
16	Fines & Penalties	1,566,840
17	Lobbying Expenses	354,153
18	Parking	27,862
19	Inventory Capitalization	2,236,929
20	Other State and Local Taxes	12,760,269
21	OtherAccruedLiabilities	12,556,315
22	Regulatory Liability	69,486,470
23	Uncollectible	6,000,000
24	Total	249,017,015
14	Income Recorded on Books Not Included in Return	
15	Equity in Subs - NIPSCO Accounts Receivable Corp	(18,468,896)
16	AFUDC Equity	28,166,688
17	Total	9,697,792
19	Deductions on Return Not Charged Against Book Income	
20	Stock Excess	1,277,582
21	OPEB	20,173,455
22	Other State and Local Taxes	1
23	Pensions	10,778,989
24	Power Tax Property	726,278,402
25	Property Plant Equipment	26,622
26	Regulatory Assets	24,966,357
27	Uncollectible	293,163
28	Total	783,794,571
27	Federal Tax Net Income	87,630,097
28	Show Computation of Tax:	
29	Federal Net Taxable Income @ 21.0%	18,402,321
30	Provision Normal - BTR & Reserve Study	(1,579,555)
31	Provision Normal - Renewables	(12,108,209)
32	Federal Income Taxes - Current Provision	4,714,557

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

TAXES ACCRUED, PREPAID AND CHARGES 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 hav to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, 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 (g) and (h). The balancing of this page is not affectec of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to cu (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.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
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 (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts chargec 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

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)	Adjustments (i)	BALANCE AT END OF YEAR: Taxes Accrued (Account 236) (j)	BALANCE AT END OF YEAR: Prepaid Taxes (Included in Account 165) (k)	DISTRIBUTION OF TAXES CHA: Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustmer to Ret. Earnings (Account 439) (n)
1	FICA/Medicare/Unemployment	Payroll Tax	Indiana	2025	4,847,723		21,948,613	22,735,568	5,917	4,066,685		9,570,735		
2	Income	Income Tax	Indiana	2025	92,939,524		3,795,548		[(a)] (85,812,358)	10,922,714		23,027,210		
3	**Subtotal Federal Tax**				97,787,247		25,744,161	22,735,568	(85,806,441)	14,989,399		32,597,945		
4	Utility Receipts	Other Taxes and Fees	Indiana	2025										
5	Unemployment Compensation	Unemployment Tax	Indiana	2025	4,535				1,381	5,916		54,084		
6	Corporate Net Income	Income Tax	Indiana	2025	19,976,337		2,108,568		[(b)] (20,010,205)	2,074,700		1,858,865		
7	Sales and Use	Sales And Use Tax	Indiana	2025	5,516,697		10,010,610	11,894,765		3,632,542		(5,414)		
8	Public Utility Fee	Other Taxes and Fees	Indiana	2025			3,845,161	3,810,479	(34,682)			2,526,877		
9	Franchise/Excise	Other Taxes and Fees	Indiana	2025	537,187					537,187				
10	**Subtotal State Tax**				26,034,756		15,964,339	15,705,244	(20,043,506)	6,250,345		4,434,412		
11	Real Estate and Personal Property	Real Estate Tax	Indiana	2025	39,407,815		52,116,709	39,356,440		52,168,084		29,074,559		
12	Severence Tax	Severance Tax	Indiana	2025										
13	**Subtotal Local Tax**				39,407,815		52,116,709	39,356,440		52,168,084		29,074,559		
40	TOTAL				163,229,818		93,825,209	77,797,252	(105,849,947)	73,407,828		66,106,916		

FOOTNOTE DATA

(a) Concept: TaxAdjustments

Any applicable Negative Deferred Income Taxes reclassed to/from Account 143.

(b) Concept: TaxAdjustments

Any applicable Negative Deferred Income Taxes reclassed to/from Account 143.

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%									
4	7%									
5	10%									
8	TOTAL Electric (Enter Total of lines 2 thru 7)									
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10	3%									
11	4%									
12	7%									
13	Gas Utility									
14	10	391,628			G411.4	170,409		221,219	34.4	`
47	OTHER TOTAL	391,628				170,409		221,219		
48	GRAND TOTAL	391,628				170,409		221,219		

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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	Investigation and Cleanup	30,268,019	242/930	8,067,107	5,580,419	27,781,331
2	Deferred Revenue	220,211	555			220,211
3	Wind Farm Development	940,853	186		139,253	1,080,106
4	Damage Billings	4,541,844	107/593	821,473	1,341,981	5,062,352
47	TOTAL	35,970,927		8,888,580	7,061,653	34,144,000

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities										
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										
16.2	Other										
17	TOTAL (Acct 281) (Total of 8, 15 and 16)										
18	Classification of TOTAL										
19	Federal Income Tax										
20	State Income Tax										
21	Local Income Tax										

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	905,928,022	119,279,376	4,740,315			254/282		254/190		1,020,467,083
3	Gas	361,301,099	36,211,683	1,413,215		15,748	254/282		254/182/190		396,083,819
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	1,267,229,121	155,491,059	6,153,530		15,748					1,416,550,902
6	Other (Non-Utility)										
9	TOTAL Account 282 (Total of Lines 5 thru 8)	1,267,229,121	155,491,059	6,153,530		15,748					1,416,550,902
10	Classification of TOTAL										
11	Federal Income Tax	1,035,866,152	126,919,490	6,153,530							1,156,632,112
12	State Income Tax	231,362,969	28,571,569			15,748					259,918,790
13	Local Income Tax										

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

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)	CHANGES DURING YEAR: Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR: Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits: Account Credited (g)	ADJUSTMENTS Debits: Amount (h)	ADJUSTMENTS Credits: Account Debited (i)	ADJUSTMENTS Credits: Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	Electric	110,969,541	47,933,482	45,842,040		2,391,047			236	47,693,315	158,363,251
9	TOTAL Electric (Total of lines 3 thru 8)	110,969,541	47,933,482	45,842,040		2,391,047				47,693,315	158,363,251
10	Gas										
11	Gas	38,834,343	7,340,599	9,907,144		687,655			236	15,694,930	51,275,073
17	TOTAL Gas (Total of lines 11 thru 16)	38,834,343	7,340,599	9,907,144		687,655				15,694,930	51,275,073
18	TOTAL Other										
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	149,803,884	55,274,082	55,749,184		3,078,702				63,388,245	209,638,325
20	Classification of TOTAL										
21	Federal Income Tax	120,676,433	45,109,986	45,801,805		2,472,147				48,092,679	165,605,146
22	State Income Tax	29,127,451	10,164,096	9,947,379		606,555				15,295,566	44,033,179
23	Local Income Tax										

NOTES

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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 (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	GAS					
2	NIPSCO Care Program - Order 44094	2,608,724		1,604,837	1,249,374	2,253,261
3	Demand Side Management- Gas - Order 44001	1,458,612		13,092,738	11,634,126	
4	FMCA Rider Deferred 80 - Order 45007/45183	3,274,606		1,269,251	953,793	2,959,148
5	Overrecovered Gas Costs - Order 43629	6,062,567	805	105,128,157	99,065,590	
6	Federal Income Tax - Gas - Order 45159/45621	83,455,119	409, 410	11,929,735		71,525,384
7	ELECTRIC					
8	Green Power - Order 44198	446,704		3,501,448	3,054,744	
9	Overrecovered Fuel Costs - Order 38706	1,672,860	501, 555	20,747,832	46,334,703	27,259,731
10	Demand Side Management - Elec - Order 43618	16,506,576		54,082,308	57,479,423	19,903,691
11	Rosewater Wind Joint Venture - Order 45194	12,579,131		247,011	194,824	12,526,944
12	Indiana Crossroads Wind Joint Venture - Order 45310	2,070,192		1,418,316	2,720,439	3,372,315
13	Dunns Bridge I Solar Joint Venture - Order 45462/45772	2,786,060		2,190,400	1,398,200	1,993,860
14	NIPSCO General			124,999	1,400,000	1,275,001
15	Federal Income Tax - Elec - Order 45159/45621	336,086,457	409, 410	76,865,121		259,221,336
16	Electric Vehicle Progam Margin - Order 44688	181,114		37,843	372,966	516,237
17	Low Income Credit - Order 46120				1,500,000	1,500,000
18	RTO Rider Deferral - Order 44156			3,652,252	5,084,653	1,432,401
19	RA Rider Deferral - Order 44155			2,784,800	11,906,511	9,121,711
20	COMBINED					
21	FAS133 - Order 38706/43629	26,229,797	175	8,863,485		17,366,312
22	ITC Federal Income Tax - Order 45159/45621	129,648	225	84,764	42,382	87,266
23	Other Miscellaneous - Order 44988	2,736,649		2,101,375	2,828,753	3,464,027
24	ITC/PTC Passback - Order 38706			112,967,546	259,214,748	146,247,202
41	TOTAL	498,284,816		422,694,218	506,435,229	582,025,827

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

Electric Operating Revenues

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.
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 page 108, 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.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	771,372,021	649,930,932	3,498,927	3,404,882	432,275	428,844
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	716,754,686	620,392,877	3,737,026	3,697,947	59,462	58,987
5	Large (or Ind.) (See Instr. 4)	582,367,887	500,011,702	8,344,789	7,984,846	2,118	2,128
6	(444) Public Street and Highway Lighting	9,447,219	8,084,152	37,144	36,652	280	280
7	(445) Other Sales to Public Authorities	2,581,228	2,432,118	14,771	15,959	423	426
8	(446) Sales to Railroads and Railways	2,996,865	2,200,841	21,776	17,876	1	1
9	(448) Interdepartmental Sales	2,157,128	2,895,974	9,452	14,698		
10	TOTAL Sales to Ultimate Consumers	2,087,677,034	1,785,948,596	15,663,885	15,172,860	494,559	490,666
11	(447) Sales for Resale					2	3
12	TOTAL Sales of Electricity	2,087,677,034	1,785,948,596	15,663,885	15,172,860	494,561	490,669
13	(Less) (449.1) Provision for Rate Refunds						
14	TOTAL Revenues Before Prov. for Refunds	2,087,677,034	1,785,948,596	15,663,885	15,172,860	494,561	490,669
15	Other Operating Revenues						
16	(450) Forfeited Discounts	6,325,613	5,108,956				
17	(451) Miscellaneous Service Revenues	[a]592,872	[c]682,070				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	2,474,779	2,435,534				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[b](23,295,238)	[d]3,756,776				
22	(456.1) Revenues from Transmission of Electricity of Others	100,248,205	89,763,503				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
25.1	(450-RTO) Other - Interest						
26	TOTAL Other Operating Revenues	86,346,231	101,746,839				
27	TOTAL Electric Operating Revenues	2,174,023,265	1,887,695,435				

Line12, column (b) includes $ 11,206,671 of unbilled revenues.
Line12, column (d) includes (30,041) MWH relating to unbilled revenues

FOOTNOTE DATA

(a) Concept: MiscellaneousServiceRevenues

	2025
Reconnect Charges (451)	$ 134,603
Other Misc Services	$ 458,269
	$ 592,872

(b) Concept: OtherElectricRevenue

	2025
Other Tracker Deferrals	$ (23,295,238)

(c) Concept: MiscellaneousServiceRevenues

	2024
Reconnect Charges (451)	$ 194,672
Other Misc Services	$ 487,398
	$ 682,070

(d) Concept: OtherElectricRevenue

	2024
Other Tracker Deferrals	$ 3,756,776

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REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (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					
2					
3					
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43					
44					
45					
46	TOTAL				

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Res - 511 - Residential	3,491,557	769,139,821	432,247	8,078	0.2203
2	Res - 550 - Street Lighting	35	9,525	26	1,346	0.2721
3	Res - 555 - Traffic and Directive Lighting	3	984	2	1,500	0.3280
4	Res - 560 - Dusk to Dawn Area Lighting	7,332	2,221,691			0.3030
41	TOTAL Billed Residential Sales	3,498,927	771,372,021	432,275	8,094	0.2205
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	3,498,927	771,372,021	432,275	8,094	0.2205

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Com - 520 - Commercial and General Service - Heat Pump	8,682	1,351,268	162	53,593	0.1556
2	Com - 521 - General Service - Small	1,606,576	352,640,891	55,013	29,204	0.2195
3	Com - 522 - Commercial Spaceheating	7,196	1,193,206	160	44,975	0.1658
4	Com - 523 - General Service - Medium	735,719	143,263,068	2,656	277,003	0.1947
5	Com - 524 - General Service - Large	686,904	117,818,768	279	2,462,022	0.1715
6	Com - 526 - Off-Peak Service	668,151	95,623,108	178	3,753,657	0.1431
7	Com - 541 - Municipal Power	15,240	2,594,835	311	49,003	0.1703
8	Com - 542 - Intermittent Wastewater Pumping	345	60,959			0.1767
9	Com - 550 - Street Lighting	2,137	329,424	677	3,157	0.1542
10	Com - 555 - Traffic and Directive Lighting	326	56,453	26	12,538	0.1732
11	Com - 560 - Dusk to Dawn Area Lighting	5,750	1,539,429	0		0.2677
12	Com - 1750 - Electric Guaranteed Minimum		283,277	0		
41	TOTAL Billed Small or Commercial	3,737,026	716,754,686	59,462	62,847	0.1918
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)					
43	TOTAL Small or Commercial	3,737,026	716,754,686	59,462	62,847	0.1918

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Ind - 521 - General Service - Small	167,786	34,587,977	1,548	108,389	0.2061
2	Ind - 523 - General Service - Medium	136,474	27,835,876	262	520,893	0.2040
3	Ind - 524 - General Service - Large	637,537	110,860,611	174	3,664,006	0.1739
4	Ind - 525 - Metal Melting Service	65,435	8,110,933	5	13,087,000	0.1240
5	Ind - 526 - Off-Peak Service	923,604	128,247,230	85	10,865,929	0.1389
6	Ind - 531 - Industrial Power Service - Large	5,953,697	222,768,337	7	850,528,143	0.0374
7	Ind - 532 - Industrial Power Service - Small	234,552	27,123,120	6	39,092,000	0.1156
8	Ind - 533 - Industrial Power Service - Small - HLF	207,040	21,950,117	3	69,013,333	0.1060
9	Ind - 541 - Municipal Power	167	32,830	4	41,750	0.1966
10	Ind - 542 - Intermittent Wastewater Pumping	5	741			0.1482
11	Ind - 543 - Station Power to Renewable Wholesale Generation Equipment	18,261	3,550,189	7	2,608,714	0.1944
12	Ind - 550 - Street Lighting	23	3,880	17	1,353	0.1687
13	Ind - 560 - Dusk to Dawn Area Lighting	208	59,174			0.2845
14	Ind - 565 - Renewable Feed-In Tariff		22,162			
15	Ind - 577 - Economic Development Rider		(2,891,244)			
16	Ind - 1750 - Electric Guaranteed Minimum		105,954			
41	TOTAL Billed Large (or Ind.) Sales	8,344,789	582,367,887	2,118	3,939,938	0.0698
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)					
43	TOTAL Large (or Ind.)	8,344,789	582,367,887	2,118	3,939,938	0.0698

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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	PS&H - 550 - Street Lighting	30,621	8,198,496	169	181,189	0.2677
2	PS&H - 555 - Traffic and Directive Lighting	6,339	1,206,355	111	57,108	0.1903
3	PS&H - 560 - Dusk to Dawn Area Lighting	184	42,368			0.2303
41	TOTAL Billed Public Street and Highway Lighting	37,144	9,447,219	280	132,657	0.2543
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	37,144	9,447,219	280	132,657	0.2543

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Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	PA - 523 - General Service - Medium	831	162,699	2	415,500	0.1958
2	PA - 541 - Municipal Power	13,908	2,410,134	420	33,114	0.1733
3	PA - 550 - Street Lighting	9	784	1	9,000	0.0871
4	PA - 560 - Dusk to Dawn Area Lighting	23	7,611			0.3309
41	TOTAL Billed Other Sales to Public Authorities	14,771	2,581,228	423	34,920	0.1747
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	14,771	2,581,228	423	34,920	0.1747

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1	R&R - 544 - Railroad Power Service	21,776	2,996,865	1	21,776,000	0.1376
41	TOTAL Billed Sales To Railroads and Railways	21,776	2,996,865	1	21,776,000	0.1376
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	21,776	2,996,865	1	21,776,000	0.1376

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Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Interdepartmental Sales	9,452	2,157,128	0		0.2282
41	TOTAL Billed Interdepartmental Sales	9,452	2,157,128			0.2282
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	9,452	2,157,128			0.2282

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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)
41	TOTAL Billed - All Accounts	15,663,885	2,087,677,034	494,559	31,672	0.1333
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts					
43	TOTAL - All Accounts	15,663,885	2,087,677,034	494,559	31,672	0.1333

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the last line of the schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the 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,line 24.
10. Footnote entries as required and provide explanations following all required data.

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)	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
1	NON-RQ:	OS									
2	Midwest ISO	OS	2								
15	Subtotal - RQ										
16	Subtotal-Non-RQ										
17	Total										

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	6,073,718	6,687,293
5	(501) Fuel	170,338,041	136,901,968
6	(502) Steam Expenses	26,767,912	19,782,053
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	4,231,401	5,213,708
10	(506) Miscellaneous Steam Power Expenses	3,619,078	2,664,553
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	211,030,150	171,249,575
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,766,525	3,335,891
16	(511) Maintenance of Structures	9,101,683	10,958,493
17	(512) Maintenance of Boiler Plant	15,843,985	19,718,440
18	(513) Maintenance of Electric Plant	10,831,632	7,744,532
18.1	(513.1) Maintenance of Computer Hardware		
18.2	(513.2) Maintenance of Computer Software		
18.3	(513.3) Maintenance of Communication Equipment		
19	(514) Maintenance of Miscellaneous Steam Plant	8,388,965	10,287,514
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	47,932,790	52,044,870
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	258,962,940	223,294,445
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
38.1	(531.1) Maintenance of Computer Hardware		
38.2	(531.2) Maintenance of Computer Software		
38.3	(531.3) Maintenance of Communication Equipment		
39	(532) Maintenance of Miscellaneous Nuclear Plant		

40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	166,314	249,643
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	88,274	93,336
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	254,588	342,979
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	165,450	194,668
54	(542) Maintenance of Structures	1,591,763	2,384,456
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,160,228	1,222,332
56	(544) Maintenance of Electric Plant	99,546	586,920
56.1	(544.1) Maintenance of Computer Hardware		
56.2	(544.2) Maintenance of Computer Software		
56.3	(544.3) Maintenance of Communication Equipment		
57	(545) Maintenance of Miscellaneous Hydraulic Plant	143,662	228,503
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	3,160,649	4,616,879
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	3,415,237	4,959,858
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	(552)	
63	(547) Fuel	85,932,982	55,243,824
64	(548) Generation Expenses	199,698	564,377
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	86,132,128	55,808,201
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	71,426	268,178
71	(553) Maintenance of Generating and Electric Plant	7,969,754	5,346,341
71.1	(553.1) Maintenance of Computer Hardware		
71.2	(553.2) Maintenance of Computer Software		
71.3	(553.3) Maintenance of Communication Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	863,096	864,609
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	8,904,276	6,479,128
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	95,036,404	62,287,329
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	147,781,778	208,770,406
76.1	(555.1) Power Purchased for Storage Operations		
76.2	(555.2) Bundled Environmental Credits		
76.3	(555.3) Unbundled Environmental Credits		
77	(556) System Control and Load Dispatching	459,725	534,917
78	(557) Other Expenses	4,775,412	(23,528,521)
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	153,016,915	185,776,802
79.1	F. Solar Generation		
79.2	Operation		
79.3	(558.1) Operation Supervision and Engineering	539,625	

79.4	(558.2) Solar Panel Generation and Other Plant Operating Expenses	5,001,170	
79.6	(558.4) Rents	4,367,967	
79.7	TOTAL Operation (Enter Total of lines 79.3 thru 79.6)	9,908,762	
79.8	Maintenance		
79.9	(558.6) Maintenance Supervision and Engineering	339,314	
79.10	(558.7) Maintenance of Solar Panels, Structures, and Equipment		
79.11	(558.8) Maintenance of Computer Hardware		
79.12	(558.9) Maintenance of Computer Software		
79.13	(558.10) Maintenance of Communication Equipment		
79.14	(558.11) Maintenance of Miscellaneous Solar Generation Plant		
79.15	TOTAL Maintenance (Enter Total of lines 79.9 thru 79.14)	339,314	
79.16	TOTAL Power Production Expenses-Solar (total of lines 79.7 & 79.15)	10,248,076	
79.17	G. Wind Generation		
79.18	Operation		
79.19	(558.13) Operation Supervision and Engineering		
79.20	(558.14) Wind Turbine Generation and Other Plant Operating Expenses		
79.21	(558.16) Rents		
79.22	TOTAL Operation (Enter Total of lines 79.19 thru 79.21)		
79.23	Maintenance		
79.24	(558.18) Maintenance Supervision and Engineering		
79.25	(558.19) Maintenance of Wind Turbines, Structures, and Equipment		
79.26	(558.20) Maintenance of Computer Hardware		
79.27	(558.21) Maintenance of Computer Software		
79.28	(558.22) Maintenance of Communication Equipment		
79.29	(558.23) Maintenance of Miscellaneous Wind Generation Plant		
79.30	TOTAL Maintenance (Enter Total of lines 79.24 thru 79.29)		
79.31	TOTAL Power Production Expenses-Wind (total of lines 79.22 & 79.30)		
79.32	H. Other Renewable Generation		
79.33	Operation		
79.34	(559.1) Operation Supervision and Engineering		
79.35	(559.2) Other Miscellaneous Generation and Other Plant Operating Expenses		
79.36	(559.3) Fuel		
79.37	(559.4) Rents		
79.38	TOTAL Operation (Enter Total of lines 79.34 thru 79.37)		
79.39	Maintenance		
79.40	(559.6) Maintenance Supervision and Engineering		
79.41	(559.7) Maintenance of Structures		
79.42	(559.9) Maintenance of Boilers		
79.43	(559.10) Maintenance of Generating and Electric Equipment		
79.44	(559.12) Maintenance of Computer Hardware		
79.45	(559.13) Maintenance of Computer Software		
79.46	(559.14) Maintenance of Communication Equipment		
79.47	(559.15) Maintenance of Miscellaneous Renewable Production Plant		
79.48	TOTAL Maintenance (Enter Total of lines 79.40 thru 79.47)		
79.49	TOTAL Power Production Expenses-Other Renewable (total of lines 79.38 & 79.48)		
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74, 79, 79.16, 79.31, & 79.49)	520,679,572	476,318,434
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,911,015	2,129,627
85	(561.1) Load Dispatch-Reliability	[a]2,680,542	[c]2,475,993
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	[b]2,118,931	[d]1,813,084
87	(561.3) Load Dispatch-Transmission Service and Scheduling	172,595	4,808,010

88	(561.4) Scheduling, System Control and Dispatch Services	200,638	176,485
89	(561.5) Reliability, Planning and Standards Development	861,874	787,196
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	34,098,893	32,740,891
93	(562) Station Expenses	1,493,588	1,215,282
94	(563) Overhead Lines Expenses	383,175	310,857
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	5,884,581	
97	(566) Miscellaneous Transmission Expenses	990,992	977,011
98	(567) Rents		
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	50,796,824	47,434,436
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,551,273	1,683,093
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	349,305	423,817
104	(569.2) Maintenance of Computer Software	1,036,281	996,396
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	6,006,166	4,934,498
108	(571) Maintenance of Overhead Lines	2,327,034	4,179,488
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	22,218	16,100
111	TOTAL Maintenance (Total of Lines 101 thru 110)	11,292,277	12,233,392
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	62,089,101	59,667,828
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	7,418,078	5,727,136
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	7,418,078	5,727,136
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 Operation Expenses (Enter Total of Lines 123 and 130)	7,418,078	5,727,136
131.1	4. ENERGY STORAGE EXPENSES		
131.2	Operation		
131.3	(577.1) Operation Supervision and Engineering		
131.4	(577.2) Operation of Energy Storage Equipment		
131.5	(577.3) Storage Fuel		
131.6	(577.4) Rents		
131.7	Total Operation (Lines 131.3 thru 131.6)		
131.8	Maintenance		

131.9	(578.1) Maintenance Supervision and Engineering		
131.10	(578.2) Maintenance of Energy Storage Equipment and Structures	26,804	
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)	26,804	
131.16	TOTAL Energy Storage Expenses (Total of 131.7 and 131.15)	26,804	
132	5. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	4,565,115	4,828,406
135	(581) Load Dispatching		
136	(582) Station Expenses	1,935,049	1,051,082
137	(583) Overhead Line Expenses	(585,176)	(636,649)
138	(584) Underground Line Expenses	6,476,185	4,615,295
139	(585) Street Lighting and Signal System Expenses	13,765	1,764
140	(586) Meter Expenses	1,123,208	2,180,937
141	(587) Customer Installations Expenses	1,511,980	1,940,673
142	(588) Miscellaneous Expenses	5,356,688	4,586,025
143	(589) Rents		
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	20,396,814	18,567,533
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,847,574	2,077,998
147	(591) Maintenance of Structures	89,074	81,306
148	(592) Maintenance of Station Equipment	2,915,861	2,518,345
148.1	(592.2) Maintenance of Computer Hardware		
148.2	(592.3) Maintenance of Computer Software		
148.3	(592.4) Maintenance of Communication Equipment		
149	(593) Maintenance of Overhead Lines	42,356,441	42,463,227
150	(594) Maintenance of Underground Lines	501,336	2,396,124
151	(595) Maintenance of Line Transformers	11,326,562	3,783,016
152	(596) Maintenance of Street Lighting and Signal Systems	70,695	228,492
153	(597) Maintenance of Meters	4,376,855	1,728,172
154	(598) Maintenance of Miscellaneous Distribution Plant	106,007	217,583
155	TOTAL Maintenance (Total of Lines 146 thru 154)	63,590,405	55,494,263
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	83,987,219	74,061,796
157	6. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,269,250	1,217,926
160	(902) Meter Reading Expenses	1,317,546	1,555,710
161	(903) Customer Records and Collection Expenses	9,276,314	8,907,360
162	(904) Uncollectible Accounts	15,179,617	6,340,378
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	27,042,727	18,021,374
165	7. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses		
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	497,533	480,641
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	497,533	480,641
172	8. SALES EXPENSES		

173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	140	69,554
176	(913) Advertising Expenses		322,270
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	140	391,824
179	9. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	84,084,099	90,823,937
182	(921) Office Supplies and Expenses	21,164,490	23,785,835
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	59,858,794	43,905,478
185	(924) Property Insurance	4,524,882	3,997,894
186	(925) Injuries and Damages	9,671,614	10,197,045
187	(926) Employee Pensions and Benefits	41,791,861	37,489,685
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	1,833,469	1,529,798
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	46,822	94,507
192	(930.2) Miscellaneous General Expenses	899,897	436,358
193	(931) Rents	7,056,174	5,268,808
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	230,932,102	217,529,345
195	Maintenance		
196	(935) Maintenance of General Plant	15,448,834	13,608,627
196.1	(935.1) Maintenance of Computer Hardware		
196.2	(935.2) Maintenance of Computer Software		
196.3	(935.3) Maintenance of Communication Equipment		
196.4	TOTAL Maintenance (Enter Total of lines 196 thru 196.3)	15,448,834	13,608,627
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196.4)	246,380,936	231,137,972
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 131.16, 156, 164, 171, 178, and 197)	948,122,110	865,807,005

FOOTNOTE DATA

(a) Concept: LoadDispatchReliability
Balance Authority portion = 702,550
(b) Concept: LoadDispatchMonitorAndOperateTransmissionSystem
Balance Authority portion = 984,225
(c) Concept: LoadDispatchReliability
Balance Authority portion = 608,510
(d) Concept: LoadDispatchMonitorAndOperateTransmissionSystem
Balance Authority portion = 775,548

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

PURCHASED POWER (Account 555)

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.

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) 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 columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

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)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES MegaWatt Hours Received (i)	POWER EXCHANGES MegaWatt Hours Delivered (j)	COST/SETTLEMENT OF POWER Demand Charges ($) (k)	COST/SETTLEMENT OF POWER Energy Charges ($) (l)	COST/SETTLEMENT OF POWER Other Charges ($) (m)	COST/SETTLEMENT OF POWER Total (k+l+m) of Settlement ($) (n)
1	Jordan Creek	OS	none				1,225,168					39,046,098		39,046,098
2	Indiana Crossroads II	OS	none				543,663					20,931,036		20,931,036
3	Carpenter Wind Farm	OS	none				67,255					2,983,090		2,983,090
4	Greenfield Mills	OS	none				410					1,652		1,652
5	Midwest ISO	OS	none				3,375,907					125,755,680		125,755,680
6	Renewable Feed-In Tariff	OS	Rate 865				71,278					12,436,187		12,436,187
7	Co-Gen Capacity Purchases	OS	Rate 878				43,046					1,708,042		1,708,042
8	Biotown	OS	none				18,883					2,542,981		2,542,981
9	Rosewater JV	OS	none				309,734					7,144,802		7,144,802
10	Indiana Crossroads Wind JV	OS	none				893,790					20,834,621		20,834,621
11	Green River Solar	OS	none				270,973					13,839,894		13,839,894
12	Appleseed Solar	OS	none				150,378					8,618,395		8,618,395
15	TOTAL						6,970,485					255,842,478		255,842,478

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the 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.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	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)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS: Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	(a) Indiana Municipal Power Agency	Various	Indiana Municipal Power Agency	OS		Various	Various		378,987	378,987	474,628			474,628
2	Wabash Valley Power Association	Various	Wabash Valley Power Association	FNO	NIPSCO Electric Rate Schedule 14	Various	Various	3,418	1,898,196	1,898,196	11,528,177			11,528,177
3	Wabash Valley Power Association	Various	Wabash Valley Power Association	OS	NIPSCO Electric Rate Schedule 14	Various	Various				658,899			658,899
4	Midcontinent Independent Systems Operator (Schedules 7 & 8)	Various	Various	OS		Various	Various						3,071,104	3,071,104
5	Midcontinent Independent Systems Operator (Schedules 1 & 2)	Various	Various	OS		Various	Various						278,183	278,183
6	Midcontinent Independent Systems Operator (Schedule 9)	Various	Various	FNO		Various	Various						4,021,327	4,021,327
7	Midcontinent Independent Systems Operator (Schedule 26)	Various	Various	OS		Various	Various						2,061,430	2,061,430
8	Midcontinent Independent Systems Operator (Schedule 26a)	Various	Various	OS		Various	Various						68,431,573	68,431,573
9	Midcontinent Independent Systems Operator (Schedule 26a adjs)	Various	Various	AD		Various	Various						3,016,463	3,016,463
10	Midcontinent Indiependent Systems Operator (Schedule 26c)	Various	Various	OS		Various	Various						2,454,675	2,454,675
11	Midcontinent Indiependent Systems Operator (Schedule 26c adjs)	Various	Various	AD		Various	Various						110,815	110,815

12	Midcontinent Independent Systems Operator (Schedule 26e)	Various	Various	OS		Various	Various						3,978,215	3,978,215
13	Midcontinent Independent Systems Operator (Schedule 26e adjs)	Various	Various	AD		Various	Various						162,716	162,716
14	Midcontinent Independent Systems Operator (Schedule 50)	Various	Various	OS		Various	Various							
35	TOTAL							3,418	2,277,183	2,277,183	12,661,704		87,586,501	100,248,205

FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority

This footnote applies to Pages 328-330 Line 1 Column e:
Grandfathered Wholesale Distribution Service Agreement accepted by the Federal Energy Regulatory Commission ("FERC" or "Commission") in Docket No. ER03-250-001 and currently designated as Service Agreement No. 569 under the tariff of Midcontinent Independent System Operator, Inc. (MISO).

This footnote applies to Pages 328-330 Lines 4-12 Column h:
All revenue is collected by MISO and distributed to NIPSCO, therefore, billing demand information is not available.

This footnote applies to Pages 328-330 Lines 2-3 Column h:
NIPSCO FERC Electric Rate Schedule No. 14.

This footnote applies to Pages 328-330 Line 4 Column d:
Long-Term Firm and Short-Term Firm Point-to-Point Service under Schedule 7 of the MISO
FERC Electric Tariff and Non-Firm Point-to-Point Service under Schedule 8 of the MISO FERC Electric Tariff.

This footnote applies to Pages 328-330 Lines 4-12 Column e:
Midcontinent Independent System Operator, Inc. - FERC Electric Tariff.

This footnote applies to Pages 328-330 Lines 4-12 Columns i-j:
All revenue is collected by MISO and distributed to NIPSCO, therefore, transfer of energy information is not available.

This footnote applies to Pages 328-330 Line 5 Column d:
Scheduling, System Control and Dispatch Service under Schedule 1 of the MISO FERC Electric Tariff and Reactive Supply and Voltage Control under Schedule 2 of the MISO FERC Electric Tariff.

This footnote applies to Pages 328-330 Line 6 Column d:
Network Integration Transmission Service under Schedule 9 of the MISO FERC Electric Tariff.

This footnote applies to Pages 328-330 Line 7 Column d:
Network Upgrades from Transmission Expansion Plan under Schedule 26, 37 and 38 of the MISO FERC Electric Tariff.

This footnote applies to Pages 328-330 Line 8 Column d:
Multi-Value Project Usage Rate under Schedule 26a of the MISO FERC Electric Tariff.

This footnote applies to Pages 328-330 Line 9 Column d:
Multi-Value Project Usage Rate Adjustments under Schedule 26a of the MISO FERC Electric Tariff.

This footnote applies to Pages 328-330 Line 10 Column d:
Targeted Market Efficiency Project under Schedule 26c of the MISO FERC Electric Tariff.

This footnote applies to Pages 328-330 Line 11 Column d:
Targeted Market Efficiency Project Adjustments under Schedule 26c of the MISO FERC Electric Tariff.

This footnote applies to Pages 328-330 Line 12 Column d:
Interregional Market Efficiency Project under Schedule 26e of the MISO FERC Electric Tariff.

This footnote applies to Pages 328-330 Line 13 Column d:
Interregional Market Efficiency Project Adjustments under Schedule 26e of the MISO FERC Electric Tariff.

This footnote applies to Pages 328-330 Line 14 Column d:
TOIF Recovery under Schedule 50 of the MISO FERC Electric Tariff.

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) 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.
4. In column (c) 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 (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
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					
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31					
32					
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35					
36					
37					
38					
39					
40					
41					
42					

43					
44					
45					
46					
47					
48					
49					
40	TOTAL				

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

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) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL							

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	301,530
2	Nuclear Power Research Expenses	256,228
3	Other Experimental and General Research Expenses	216,577
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	77,509
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Consultants and Contract Services	24,362
7	Fees and Permits	10,969
8	Utilities	5,984
9	Employee Expenses	4,523
10	Miscellaneous	2,215
46	TOTAL	899,897

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

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 B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section 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 of 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	154,113,091				154,113,091
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	6,326,567				6,326,567
5	Hydraulic Production Plant-Pumped Storage					
5.1	Solar Production Plant	30,508,398				30,508,398
5.2	Wind Production Plant	613,095				613,095
5.3	Other Renewable Production Plant					
6	Other Production Plant	11,754,272				11,754,272
7	Transmission Plant	52,644,209				52,644,209
8	Distribution Plant	84,741,297				84,741,297
9	Regional Transmission and Market Operation					
9.1	Energy Storage Plant	3,293,667				3,293,667
10	General Plant	16,157,259		[a]6,959		16,164,218
11	Common Plant-Electric	22,971,153				22,971,153
12	TOTAL	383,123,008		6,959		383,129,967

B. Basis for Amortization Charges

Asset: Computer Software Term: 3 - 10 years Amortization: $40,762,290 Method: Straight Line Asset: Leasehold Improvements Term: 7 years Amortization: $6,959 Method: Straight Line *Term is based on assets with remaining life

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Electric Utility						
13	311 Generating Stations	503.257	110 years	(8)	6.61	R2.5	1 year
14	311 Sugar Creek	8.147	55 years	(20)	6.61	R2.5	43 years, 6 months
15	312 Generating Stations	1,286.939	55 years	(8)	6.53	S0	1 year
16	312 Sugar Creek	97.527	55 years	(20)	6.06	S0	43 years, 6 months
17	314 Generating Stations	302.362	60 years	(8)	5.59	R2	1 year
18	314 Sugar Creek	55.995	60 years	(20)	5.59	R2	43 years, 6 months
19	315 Generating Stations	201.627	65 years	(8)	5.94	R2	1 year
20	315 Sugar Creek	4.712	65 years	(20)	5.94	R2	43 years, 6 months
21	Computer Hardware	3.278	7 years		15.58	SQ	
22	Computer Software	5.317					
23	Communication Equipment	2.273	15 years		8.71	SQ	
24	316 Generating Stations	40.725	70 years	(8)	5.5	R1.5	1 year
25	316 Sugar Creek	3.777	70 years	(20)	5.5	R1.5	43 years, 6 months

26	Subtotal Electric Utility:	2,515.936						
27	331 Hydro	12.062	70 years	(9)	4.17	S1	12 years	
28	332 Hydro	65.045	85 years	(7)	6.61	R3	12 years	
29	333 Hydro	15.002	75 years	(7)	5.51	R2	12 years	
30	334 Hydro	2.725	55 years	(7)	4.18	L1.5	12 years	
31	334.1 Hydro		7 years		15.58	SQ		
32	334.2 Hydro	0.135						
33	334.3 Hydro	5.407	15 years		8.71	SQ		
34	335 Hydro	1.717	55 years	(7)	4.94	S0.5	12 years	
35	Hydro Production Subtotal	102.093						
36	338.2 Generating Stations	0.161	20 years		4	S2.5		
37	338.2 CAV Cavalry	54.669	30 years		3.3	S2.5	30 years	
38	338.2 DB2 Dunns Bridge 2	115.982	30 years		3.3	S2.5	30 years	
39	338.2 FBK Fairbanks	81.165	30 years		3.3	S2.5	30 years	
40	338.2 GIB Gibson	45.227	30 years		3.3	S2.5	30 years	
41	338.4 Generating Stations	0.946	20 years		5.35	S2.5		
42	338.4 CAV Cavalry	230.949	30 years		3.3	S2.5	30 years	
43	338.4 DB2 Dunns Bridge 2	325.199	30 years		3.3	S2.5	30 years	
44	338.4 FBK Fairbanks	260.136	30 years		3.3	S2.5	30 years	
45	338.4 GIB Gibson	226.262	30 years		3.3	S2.5	30 years	
46	338.5 CAV Cavalry	0.012	30 years		3.3	S2.5	30 years	
47	338.5 DB2 Dunns Bridge 2	130.723	30 years		3.3	S2.5	30 years	
48	338.5 FBK Fairbanks	86.414	30 years		3.3	S2.5	30 years	
49	338.5 GIB Gibson	68.797	30 years		3.3	S2.5	30 years	
50	338.6 Generating Stations		20 years		5.35	S2.5		
51	338.6 CAV Cavalry	0.001	30 years		3.3	S2.5	30 years	
52	338.6 DB2 Dunns Bridge 2	10.026	30 years		3.3	S2.5	30 years	
53	338.6 FBK Fairbanks	5.859	30 years		3.3	S2.5	30 years	
54	338.6 GIB Gibson	4.665	30 years		3.3	S2.5	30 years	
55	338.7 Generating Stations	0.236	20 years		5.73	S2.5		
56	338.7 CAV Cavalry	0.005	30 years		3.3	S2.5	30 years	
57	338.7 DB2 Dunns Bridge 2	55.522	30 years		3.3	S2.5	30 years	
58	338.7 FBK Fairbanks	34.808	30 years		3.3	S2.5	30 years	
59	338.7 GIB Gibson	27.712	30 years		3.3	S2.5	30 years	
60	338.8 Generating Stations		20 years		5.73	S2.5		
61	338.8 CAV Cavalry	35.24	30 years		3.3	S2.5	30 years	
62	338.8 DB2 Dunns Bridge 2	28.225	30 years		3.3	S2.5	30 years	
63	338.8 FBK Fairbanks	19.48	30 years		3.3	S2.5	30 years	
64	338.8 GIB Gibson	17.861	30 years		3.3	S2.5	30 years	
65	338.9 Solar	4.734	7 years		15.58	SQ		
66	338.10 Solar	5.908						
67	338.11 Solar	1.171	15 years		8.71	SQ		
68	338.12 Generating Stations		20 years		5.73	S2.5		
69	338.12 CAV Cavalry	0.917	30 years		3.3	S2.5	30 years	

70	338.12 DB2 Dunns Bridge 2		30 years		3.3	S2.5	30 years
71	338.12 FBK Fairbanks		30 years		3.3	S2.5	30 years
72	338.12 GIB Gibson		30 years		3.3	S2.5	30 years
73	Solar Production Subtotal	1,879.012					
74	338.20 Land and land rights.						
75	338.21 Structures and improvements.						
76	338.22 [Reserved]						
77	338.23 Wind turbines.						
78	338.24 Wind towers and fixtures.						
79	338.25 [Reserved]						
80	338.26 Collector system.						
81	338.27 Generator step-up transformers (GSU).						
82	338.28 Inverters.						
83	338.29 Other accessory electrical equipment.						
84	338.30 Computer hardware.				15.58		
85	338.31 Computer software.	1.891					
86	338.32 Communication equipment.						
87	338.33 Miscellaneous power plant equipment.						
88	Wind Production Subtotal	1.891					
89	341 Other	4.881	50 years	(6)	3.47	S2.5	1 year
90	341 Sugar Creek	13.302	50 years	(7)	3.47	S2.5	13 years, 6 months
91	342 Other	8.742	50 years	(3)	5.31	S2.5	1 year
92	342 Sugar Creek	3.078	50 years	(7)	5.31	S2.5	13 years, 6 months
93	343 Other	39.136	50 years	(3)	1.73	R1	1 year
94	343 Sugar Creek	114.512	50 years	(7)	1.73	R1	13 years, 6 months
95	344 Other	7.876	55 years	(3)	1.89	R3	1 year
96	344 Sugar Creek	38.92	55 years	(7)	1.89	R3	13 years, 6 months
97	345 Other	18.531	50 years	(3)	6.06	S1	1 year
98	345 Sugar Creek	33.223	50 years	(7)	6.06	S1	13 years, 6 months
99	345.1 Computer Hardware	7.007	7 years		15.58	SQ	
100	345.2 ComputerSoftware	15.01					
101	345.3 Computer Equipment		7 years		8.71	SQ	
102	346 Other	0.509	55 years	(3)	3.11	R2.5	1 year
103	346 Sugar Creek	5.295	55 years	(7)	3.11	R2.5	13 years, 6 months
104	Other Production Subtotal	310.022					
105	350.2 Transmission	16.961	75 years		1.27	R4	
106	350.2 Transmission Tracker	52.01	75 years		1.27	R4	
107	351 Transmission				8.71		

108	351 Transmission Tracker				8.71			
109	351.1 Computer Hardware	3.446	7 years		15.58	SQ		
110	351.2 Computer Software	0.013						
111	351.3 Computer Equipment	75.974	15 years		8.71	SQ		
112	351.3 Tracker	0.751	15 years		8.71	SQ		
113	352 Transmission	135.638	65 years	(15)	1.66	R1.5		
114	352 Transmission Tracker	22.427	65 years	(15)	1.36			
115	353 Transmission	907.194	52 years	(10)	1.89	S0		
116	353 Transmission Tracker	163.052	52 years	(10)	1.84	S0		
117	354 Transmission	196.815	75 years	(26)	1.26	R4		
118	354 Transmission Tracker	42.714	75 years	(26)	1.26	R4		
119	355 Transmission	422.88	62 years	(35)	2	R1		
120	355 Transmission Tracker	239.973	62 years	(35)	2	R1		
121	356 Transmission	310.376	68 years	(40)	1.82	R2		
122	356 Transmission Tracker	98.516	68 years	(40)	1.82	R2		
123	357 Transmission	0.088	65 years	(5)	0.62	S4		
124	358 Transmission	4.132	50 years	(5)	1.79	R1.5		
125	358 Transmission Tracker		50 years	(5)	1.79	R1.5		
126	359 Transmission	0.001	70 years		0.56	R4		
127	Transmission Total	2,692.961						
128	360.2 Distribution	1.682	75 years		1.26	R4		
129	360.2 Distribution Tracker		75 years		1.26	R4		
130	361 Distribution	28.699	65 years	(15)	1.23	R1.5		
131	361 Distribution Tracker		65 years	(15)	1.23	R1.5		
132	362 Distribution	710.813	50 years	(10)	1.98	R1.5		
133	362 Distribution Tracker	10.92	50 years	(10)	1.98	R1.5		
134	363 Distribution							
135	363 Distribution Tracker							
136	363.1 Computer Hardware	2.703	7 years		15.58	SQ		
137	363.2 Computer Software	21.371						
138	363.3 Computer Equipment	56.82	15 years		8.71	SQ		
139	364 Distribution	788.442	47 years	(53)	2.9	R1		
140	364 Distribution Tracker	14.329	47 years	(53)	2.9	R1		
141	365 Distribution	468.154	65 years	(60)	1.82	R1		
142	365 Distribution Tracker	7.721	65 years	(60)	1.82	R1		
143	366 Distribution	5.167	70 years	(5)	1.38	S2.5		
144	367 Distribution	670.716	52 years	(30)	2.3	R2		
145	367 Distribution Tracker	22.019	52 years	(30)	2.3	R2		
146	368 Distribution	448.085	47 years	(8)	1.87	S0		
147	368 Distribution Tracker	0.598	47 years	(8)	1.87	S0		
148	369 Distribution	357.873	70 years	(32)	1.34	R3		
149	369 Distribution Track		70 years	(32)		R3		
150	370 Distribution	111.904	24 years	(2)	3.4	L0		

151	370 Distribution Tracker		24 years	(2)		L0	
152	371 Distribution	11.428	20 years	(25)	3.55	O1	
153	373 Distribution	64.932	31 years	(30)	3.55	L0	
154	373 Distribution Tracker		31 years	(30)	3.55	L0	
155	Distribution Total	3,804.376					
156	387.2 DB2 Dunns Bridge 2	4.385	30 years			S2.5	30 years
157	387.2 CAV Cavalry	2.394	30 years			S2.5	30 years
158	387.3 DB2 Dunns Bridge 2	87.099	30 years			S2.5	30 years
159	387.3 CAV Cavalry	54.89	30 years			S2.5	30 years
160	387.5 DB2 Dunns Bridge 2	4.594	30 years			S2.5	30 years
161	387.5 CAV Cavalry	0.001	30 years			S2.5	30 years
162	387.7 DB2 Dunns Bridge 2	8.62	30 years			S2.5	30 years
163	387.7 CAV Cavalry	0.001	30 years			S2.5	30 years
164	387.8 Computer Hardware	1.383	7 years			SQ	
165	387.9 Computer Software	2.011					
166	387.10 Communication equipment	0.073	15 years			SQ	
167	387.11 DB2 Dunns Bridge 2	1.437	30 years			S2.5	30 years
168	387.11 CAV Cavalry	5.278	30 years			S2.5	30 years
169	Energy Storage Subtotal	172.166					
170	390 General	34.097	55 years	(10)	1.43	R1.5	
171	391 General	5.05	20 years			SQ	
172	392 General	3.544			6.89		
173	393 General	0.84			1.46		
174	394 General	33.84			3.83		
175	395 General	6.025	20 years		2.07	SQ	
176	396 General	5.244			9.19		
177	397 General				8.71		
178	397 Tracker				8.71		
179	397.1 Computer Hardware	7.1	7 years		15.16	SQ	
180	397.2 Computer Software	89.111					
181	397.3 Communication Equipment	21.442	15 years		8.71	SQ	
182	398 General	6.59	20 years		5.19	SQ	
183	General Total	212.883					
184	Ending Balance	11,691.34					

FOOTNOTE DATA

(a) Concept: AmortizationOfLimitedTermPlantOrProperty

Asset:	Term:	Amort Exp:	Method:
Computer Software	3-10 years*	40,762,290	Straight Line
Leasehold Improvements	7 years*	6,959	Straight Line

*Term is based on assets with remaining life

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
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 columns (f), (g), and (h), expenses incurred during the 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						
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	Indiana Utility Regulatory Commission (IURC)											
2	Cause #43969, 2016 Electric Rate Case				(137)				137	923		
3	Cause #45159, 2018 Electric Rate Case				544,840				1,127	923	273,052	272,915
4	Cause #44988, 2018 Gas Rate Case				125,330					923	125,330	
5	Cause #45621, 2021 Gas Rate Case				746,466				(140,540)	923	167,751	438,175
6	Cause #45772, 2022 Electric Rate Case				1,826,118				77,376	923	716,621	1,186,873
7	Cause #45967, 2023 Gas Rate Case				1,381,769				25,190	923	377,250	1,029,709
8	Cause #46120, 2024 Electric Rate Case				1,589,203				856,626	923	323,281	2,122,548
9	2025 Gas Rate Case								235,741	923		235,741
10	Midcontinent Independent System Operator (MISO)											
11	Schedule 10 Fees		2,004,576	2,004,576			928	2,004,576				
46	TOTAL		2,004,576	2,004,576	6,213,589			2,004,576	1,055,657		1,983,285	5,285,961

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
   Classifications:

   Electric R, D and D Performed Internally:

   Generation

   hydroelectric

   Recreation fish and wildlife
   Other hydroelectric

   Fossil-fuel steam
   Internal combustion or gas turbine
   Nuclear
   Solar
   Wind
   Other renewable
   Unconventional generation
   Siting and heat rejection

   Transmission

   Overhead
   Underground

   Distribution
   Regional Transmission and Market Operation
   Energy Storage
   Environment (other than equipment)
   Other (Classify and include items in excess of $50,000.)
   Total Cost Incurred

   Electric, R, D and D Performed Externally:

   Research Support to the electrical Research Council or the Electric Power Research Institute
   Research Support to Edison Electric Institute
   Research Support to Nuclear Power Groups
   Research Support to Others (Classify)
   Total Cost Incurred
3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	B (2)	Research support to Edison Electric Institute (a)		15,000	426	15,000	
2	B (2)	Research support to Edison Electric Institute (b)		580,005	921	580,005	
3	B (2)	Research support to Edison Electric Institute (c)		16,500	930	16,500	
4	B (1)	Research support to Electric Power Research Institute (a)		216,543	921	216,543	
5	B (1)	Research support to Electric Power Research Institute (b)		213,211	923	213,211	
6	B (4)	Research support to Indiana Energy Association		607,742	921	607,742	
7	B (4)	Research support to North American Electric Reliability Group		879,344	921	879,344	
8	Total			2,528,345		2,528,345	

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	17,467,183		
4	Transmission	6,768,579		
5	Regional Market			
5.1	Energy Storage			
6	Distribution	6,610,558		
7	Customer Accounts	7,143,827		
8	Customer Service and Informational	122,154		
9	Sales			
10	Administrative and General	24,811,390		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	62,923,691		
12	Maintenance			
13	Production	14,912,932		
14	Transmission	4,417,342		
15	Regional Market			
15.1	Energy Storage			
16	Distribution	14,962,161		
17	Administrative and General	86,496		
18	TOTAL Maintenance (Total of lines 13 thru 17)	34,378,931		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	32,380,115		
21	Transmission (Enter Total of lines 4 and 14)	11,185,921		
22	Regional Market (Enter Total of Lines 5 and 15)			
22.1	Energy Storage (Enter Total of Lines 5.1 and 15.1)			
23	Distribution (Enter Total of lines 6 and 16)	21,572,719		
24	Customer Accounts (Transcribe from line 7)	7,143,827		
25	Customer Service and Informational (Transcribe from line 8)	122,154		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	24,897,886		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	97,302,622	29,504,312	126,806,934
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	3,091,001		
35	Transmission	4,062,426		
36	Distribution	9,108,307		
37	Customer Accounts	11,482,750		
38	Customer Service and Informational	215,781		
39	Sales			
40	Administrative and General	11,895,482		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	39,855,747		

42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	656,423		
47	Transmission	1,796,497		
48	Distribution	11,277,215		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	13,730,135		
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	3,747,424		
56	Transmission (Lines 35 and 47)	5,858,923		
57	Distribution (Lines 36 and 48)	20,385,522		
58	Customer Accounts (Line 37)	11,482,750		
59	Customer Service and Informational (Line 38)	215,781		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	11,895,482		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	53,585,882	20,182,527	73,768,409
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	150,888,504	49,686,839	200,575,343
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	62,985,110	23,205,577	86,190,687
69	Gas Plant	44,005,116	18,663,517	62,668,633
70	Other (provide details in footnote):	9,587,523	184,996	9,772,519
71	TOTAL Construction (Total of lines 68 thru 70)	116,577,749	42,054,090	158,631,839
72	Plant Removal (By Utility Departments)			
73	Electric Plant	3,769,348	1,912,810	5,682,158
74	Gas Plant	5,023,955	2,591,638	7,615,593
75	Other (provide details in footnote):		4	4
76	TOTAL Plant Removal (Total of lines 73 thru 75)	8,793,303	4,504,452	13,297,755
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts:			
79	Accounts receivable from associated companies	1,738,376	1,262,443	3,000,819
80	Fuel stock expenses undistributed	5,425,336	1,298,283	6,723,619
81	Plant Materials & Operating Supplies		34	34
82	Stores expense undistributed	5,860,728	(5,860,728)	
83	Misc. Prepayments		12,458	12,458
84	Other regulatory assets	475,887	3,213,535	3,689,422
85	Preliminary survey and investigation charges	421,202	107,872	529,074
86	Clearing accounts	63,202,922	(67,037,580)	(3,834,658)
87	Miscellaneous deferred debits	1,503	411,833	413,336
88	Accumulated miscellaneous operating provisions			
89	Accounts payable to associated companies	(81,806)	(734,169)	(815,975)
90	Miscellaneous current and accrued liabilities	23,127,753	(28,268,092)	(5,140,339)
91	Other deferred credits	1,814	1,751	3,565
92	Other regulatory liabilities	334,665	415,520	750,185
93	Donations	316	30,781	31,097

94				
95	TOTAL Other Accounts	100,508,696	(95,146,059)	5,362,637
96	TOTAL SALARIES AND WAGES	376,768,252	1,099,322	377,867,574

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

Account (a)	Balance Beginning Of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance End Of Year (g)
Account 101 & 106						
301 - Organization	126,863	—	—	—	—	126,863
303 - Intangible	386,361,350	53,047,796	—	—	—	439,409,146
360 - Land Rights	—	—	—	—	—	—
389 - Land & Land Rights	8,464,360	—	—	—	—	8,464,360
390 - Structures & Improvements	119,699,815	3,792,195	(558,096)	—	—	122,933,914
391 - Office Furniture & Equipment	17,222,420	2,115,550	(3,234,560)	—	—	16,103,410
392 - Transportation Equipment	10,272,520	302,579	—	—	—	10,575,099
393 - Stores Equipment	2,733,827	42,327	(84,523)	—	—	2,691,631
394 - Tool, Shop & Garage Equipment	9,777,236	885,160	(31,331)	—	—	10,631,065
395 - Laboratory Equipment	2,562,391	157,657	(30,587)	—	—	2,689,461
396 - Power Operated Equipment	5,463,156	—	(1,426)	—	—	5,461,730
397 - Communication Equipment	12,486,573	90,924	(1,469,825)	—	—	11,107,672
398 - Miscellaneous Equipment	3,700,077	13,381	—	—	—	3,713,458
Total Acct. 101 & 106	578,870,588	60,447,569	(5,410,348)	—	—	633,907,809
Account 101 & 106-Common Utility						
Acct. 101.1 Right of Use	2,561,523	105,316	—	(647,951)		2,018,888
Acct. 101.1 Capital Leases	52,000	720,286	—	—	—	772,286
Total Common Utility Plant	581,484,111	61,273,171	(5,410,348)	(647,951)	—	636,698,983
Less: Account 303-Intangibles: Balance End of year for Customer based software system asset costs allocated on different basis than other Common 303 Intangible Assets						69,635,813
Less: Account 303-Intangibles: Balance End of year for Customer based software system asset costs allocated on different basis than other Common 303 Intangible Assets						40,294,113
Total Common Utility Plant Excluding Account 303 defined above						526,769,057
Allocation of Common Utility Plant (1)						

	Ratio H	Allocation of Common Utility Plant Excluding Intangible Assets Customer Based	Ratio G2	Allocation of Common Intangible Assets Customer Based	Ratio MS	Allocation of Common Intangible Assets Customer Based	Total
Electric	71.07 %	374,392,189	36.16 %	25,183,504	67.56 %	27,221,832	426,797,525
Gas	28.93 %	152,376,868	63.84 %	44,452,309	32.44 %	13,072,281	209,901,458
Total	100.00 %	526,769,057	100.00 %	69,635,813	100.00 %	40,294,113	636,698,983

(1) Allocation of Common Utility Plant is based on generally accepted factors used for allocating those common types of assets and expenses which are utilized or indirectly impacting both the electric and gas departments. The allocation factors used are reflective of the current allocation process implemented in 2007.

Accumulated Provision for Depreciation of Common Utility Plant (Account 108):

	Common Plant in Service	Allocated to Electric	Allocated to Gas
Balance Beginning of Year	87,562,546		
Depr Provision for year charge to (403) Depr Expense	6,832,446	4,856,045	1,976,401
Transportation Expenses - Clearing	0		
Other Accounts: Transfers between Pl. Accts	0		
Total Depr Provision for Year	6,832,446		
Net Charges for Plant Retired:			
Book Cost of Plant Retired	5,410,348		
Cost of Removal	309,862		
Salvage (Credit)	0		
Total Net Charges for Plant Retired	5,720,210		
Other Credit Transfers	(8,200)		
Retirement Work in Progress	(221,071)		
Balance End of Year	88,887,653	63,175,395	25,712,258
Allocation Basis: Ratio H		71.07 %	28.93 %

Accumulated Provision for Amortization of Common Utility Plant (Account 111):

	Common Plant in Service	Allocated to Electric	Allocated to Gas
Balance Beginning of Year	318,323,759		
Amortization Provisions for year, charge to (404) Amortization Expense	32,858,424	23,353,568	9,504,856
Other Accounts:	0		
Total Amortization Provision for Year	32,858,424		
Net Charges for Plant Retired:			
Cost of Removal	0		
Other Credit Transfers	8,200		
Balance End of Year	351,190,383		
Allocation Basis: Ratio H	241,260,457	171,471,785	69,788,672
		71.07 %	28.93 %
Allocation Basis: Ration G-2	69,635,813	25,183,504	44,452,309
		36.16 %	63.84 %
Allocation Basis: Ratio MS	40,294,113	27,221,832	13,072,281
		67.56 %	32.44 %
Balance End of Year	351,190,383	223,877,121	127,313,262

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchase 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)	34,988,795	79,824,371	153,527,807	218,978,332
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(10,695,826)	(18,704,650)	(28,784,395)	(37,688,052)
4	Transmission Rights	756,684	(429,347)	(1,899,953)	(4,716,331)
5	Ancillary Services	(1,376,020)	(3,005,837)	(2,818,426)	(4,690,397)
6	Other Items (list separately)				
7	Revenue Sufficiency Guarantee	(76,821)	(88,209)	(254,873)	(247,956)
8	Distribution of Losses	(1,329,382)	(2,158,256)	(4,439,109)	(5,584,527)
9	Inadvertent Energy	8,793	75,502	25,167	65,723
10	Resource Adequacy	435,796	16,423,063	44,132,418	37,338,463
46	TOTAL	22,712,019	71,936,637	159,488,636	203,455,255

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) 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)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	5	MW	157,168			468,558
2	Reactive Supply and Voltage	5	MW	9,359			(6,150)
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other	5	MW	2,260			
8	Total (Lines 1 thru 7)	15		168,787	0		462,408

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported 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.

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)
	NAME OF SYSTEM: Northern Indiana Public Service Company LLC									
1	January	2,690	21	20	2,285	346				59
2	February	2,713	14	8	2,327	327				59
3	March	2,471	6	10	2,139	278				54
4	Total for Quarter 1				6,751	951	0	0	0	172
5	April	2,234	29	11	1,914	271				49
6	May	2,778	15	17	2,374	343				61
7	June	3,456	26	14	2,931	449				76
8	Total for Quarter 2				7,219	1,063	0	0	0	186
9	July	3,566	24	14	2,994	494				78
10	August	3,469	16	14	2,943	450				76
11	September	2,939	19	14	2,498	377				64
12	Total for Quarter 3				8,435	1,321	0	0	0	218
13	October	2,765	3	14	2,360	344				61
14	November	2,369	20	11	2,038	279				52
15	December	2,772	15	10	2,371	340				61
16	Total for Quarter 4				6,769	963	0	0	0	174
17	Total				29,174	4,298	0	0	0	750

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

Monthly ISO/RTO 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 Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: Northern Indiana Public Service Company LLC									
1	January	2,690	21	20				2,690		2,690
2	February	2,713	14	8				2,713		2,713
3	March	2,471	6	10				2,471		2,471
4	Total for Quarter 1				0	0	0	7,874	0	7,874
5	April	2,234	29	11				2,234		2,234
6	May	2,778	15	17				2,778		2,778
7	June	3,456	26	14				3,456		3,456
8	Total for Quarter 2				0	0	0	8,468	0	8,468
9	July	3,566	24	14				3,566		3,566
10	August	3,469	16	14				3,469		3,469
11	September	2,939	19	14				2,939		2,939
12	Total for Quarter 3				0	0	0	9,974	0	9,974
13	October	2,765	3	14				2,765		2,765
14	November	2,369	20	11				2,369		2,369
15	December	2,772	15	10				2,772		2,772
16	Total for Quarter 4				0	0	0	7,906	0	7,906
17	Total Year to Date/Year				0	0	0	34,222	0	34,222

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2026-04-20	Year/Period of Report End of: 2025/ Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	15,663,885
3	Steam	4,679,531	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	14,170	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
6.1	Solar	1,934,565	27	Total Energy Losses	458,884
6.2	Wind		27.1	Total Energy Stored	
6.3	Other Renewable		28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	16,122,769
7	Other	2,524,018			
8	Less Energy for Pumping				
9	Net Generation (Enter Total of lines 3 through 8)	9,152,284			
10	Purchases (other than for Energy Storage)	6,970,485			
10.1	Purchases for Energy Storage				
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received	2,277,183			
17	Delivered	2,277,183			
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	16,122,769			

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

MONTHLY PEAKS AND OUTPUT

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

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: Northern Indiana Public Service Company LLC					
29	January	1,467,297		2,346	22	8
30	February	1,177,818		2,338	14	9
31	March	1,468,399		2,154	24	16
32	April	1,210,481		1,944	29	11
33	May	1,285,042		2,424	15	17
34	June	1,490,015		2,938	26	13
35	July	1,734,576		3,042	24	15
36	August	1,573,159		2,988	16	16
37	September	1,380,741		2,546	19	15
38	October	1,285,966		2,406	3	15
39	November	1,278,051		2,054	20	12
40	December	1,356,462		2,333	15	11
41	Total	16,708,007	0			

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

Steam Electric Generating Plant Statistics

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 Mcf.
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.
9. Items under Cost of Plant are based on USofA 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.

Line No.	Item (a)	Plant Name: Michigan City (Steam)	Plant Name: RM Schahfer (Combustion Turbine)	Plant Name: RM Schahfer (Steam)	Plant Name: Sugar Creek (Combine Cycle)	Plant Name: Sugar Creek (Steam)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Gas Turbine	Steam	Combined Cycle	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional	Conventional	Outdoor	
3	Year Originally Constructed	1929	1979	1976	2002	
4	Year Last Unit was Installed	1974	1979	1986	2003	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	540	258	847	620	0
6	Net Peak Demand on Plant - MW (60 minutes)	449	0	792	0	0
7	Plant Hours Connected to Load	5,867	1,214	7,133	20,691	0
8	Net Continuous Plant Capability (Megawatts)	455	155	2,105	316	237
9	When Not Limited by Condenser Water	0	0	1,625	0	0
10	When Limited by Condenser Water	0	0	0	0	0
11	Average Number of Employees	0	0	0	0	0
12	Net Generation, Exclusive of Plant Use - kWh	1,965,468,136	82,743,595	1,454,704,302	3,793,485,863	1,350,724,000
13	Cost of Plant: Land and Land Rights	596,635	0	3,233,956	995,262	0
14	Structures and Improvements	153,925,552	2,509,187	349,334,149	13,302,480	8,147,435
15	Equipment Costs	732,524,801	74,674,906	1,106,746,955	195,767,107	163,029,762
16	Asset Retirement Costs	0	0	0	0	0
17	Total Cost (10-23)	887,046,988	77,184,093	1,459,315,060	210,064,849	171,177,197
18	Cost per KW of Installed Capacity (line 17/5) Including	1,642.6796	299.1632	1,722.9221	338.8143	0.0000
19	Production Expenses: Oper, Supv, & Engr	1,203,457	0	4,381,405	0	365,895
20	Fuel	63,136,737	4,347,884	89,773,041	81,585,098	5,868,246
21	Coolants and Water (Nuclear Plants Only)	0	0	0	0	0
22	Steam Expenses	5,678,035	0	20,797,525	0	62,810
23	Steam From Other Sources	0	0	0	0	0
24	Steam Transferred (Cr)	0	0	0	0	0
25	Electric Expenses	1,630,436	0	2,318,958	199,698	161,234
26	Misc Steam (or Nuclear) Power Expenses	1,374,734	0	791,205	0	1,424,000
27	Rents	0	0	0	0	0
28	Allowances	0	0	0	0	0
29	Maintenance Supervision and Engineering	925,427	0	2,770,689	0	70,408
30	Maintenance of Structures	2,642,199	0	6,448,760	71,426	3,002
31	Maintenance of Boiler (or reactor) Plant	8,560,557	0	5,801,789	0	1,434,938
32	Maintenance of Electric Plant	1,071,397	1,253,356	8,139,459	6,708,572	1,619,154
33	Maintenance of Misc Steam (or Nuclear) Plant	2,035,760	0	6,332,670	863,096	150,535
34	Total Production Expenses	88,258,739	5,601,240	147,555,501	89,427,890	11,160,222
35	Expenses per Net kWh	0.0449	0.0677	0.1014	0.0236	0.0083

35	**Plant Name**	Michigan City (Steam)	Michigan City (Steam)	RM Schahfer (Combustion Turbine)	RM Schahfer (Steam)	RM Schahfer (Steam)	Sugar Creek (Combine Cycle)

36	Fuel Kind	Coal	Gas	Gas	Coal	Gas	Gas
37	Fuel Unit	T	Mcf	Mcf	T	Mcf	Mcf
38	Quantity (Units) of Fuel Burned	1,069,561	337	1,160	789,019	105	25,190
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9,565	1,049	1,065	11,036	1,047	1,063
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year						
41	Average Cost of Fuel per Unit Burned						
42	Average Cost of Fuel Burned per Million BTU						
43	Average Cost of Fuel Burned per kWh Net Gen						
44	Average BTU per kWh Net Generation		10,590	14,934		12,047	7,058

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

Renewable Generating Plant Statistics

1. Report data for plant in Service only.
2. Report in this page renewable plants of 10,000 Kw or more.
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. 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.

Line No.	Item (a)	Plant Name: 0
1	Kind of Plant (Solar, Wind, Biomass, etc.)	
2	Type of Constr (PV Tracking, Offshore, Boiler, etc)	
3	Year Originally Constructed	
4	Year Last Unit was Installed	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	
6	Net Peak Demand on Plant - MW (60 minutes)	
7	Plant Hours Connected to Load	
8	Net Continuous Plant Capability (Megawatts)	
9	Net Generation, Exclusive of Plant Use - KWh	
10	Cost of Plant: Land and Land Rights	
11	Structures and Improvements	
12	Solar Panels, Wind Turbines and Generators	
13	Fuel Holders	
14	Boilers	
15	Collector System	
16	Generator Step-up Transformers (GSU)	
17	Inverters	
18	Other Accessory Electrical Equipment	
19	Computer Hardware	
20	Computer Software	
21	Communication Equipment	
22	Miscellaneous Power Plant Equipment	
23	Asset Retirement Costs	
24	Total Cost (10-23)	
25	Cost per KW of Installed Capacity (line 24/5) Including	
26	Production Expenses: Oper, Supv, & Engr	
27	Generation and Other Plant Operating Expenses	
28	Fuel	
29	Steam Expenses	
30	Electric Expenses	
31	Misc Steam Power Expenses	
32	Rents	
33	Environmental Credits	
34	Maintenance Supervision and Engineering	
35	Maintenance of Structures and Equipment	
36	Maintenance of Boiler Plant	
37	Maintenance of Electric Plant	
38	Maintenance of Computer Hardware	
39	Maintenance of Computer Software	
40	Maintenance of Communication Equipment	
41	Maintenance of Misc Plant	
42	Total Production Expenses	
43	Expenses per Net KWh	

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Kind of Plant (Run-of-River or Storage)	
2	Plant Construction type (Conventional or Outdoor)	
3	Year Originally Constructed	
4	Year Last Unit was Installed	
5	Total installed cap (Gen name plate Rating in MW)	
6	Net Peak Demand on Plant-Megawatts (60 minutes)	
7	Plant Hours Connect to Load	
8	**Net Plant Capability (in megawatts)**	
9	(a) Under Most Favorable Oper Conditions	
10	(b) Under the Most Adverse Oper Conditions	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	
13	**Cost of Plant**	
14	Land and Land Rights	
15	Structures and Improvements	
16	Reservoirs, Dams, and Waterways	
17	Equipment Costs	
18	Roads, Railroads, and Bridges	
19	Asset Retirement Costs	
20	Total Cost (10-23)	
21	Cost per KW of Installed Capacity (line 20 / 5)	
22	**Production Expenses**	
23	Operation Supervision and Engineering	
24	Water for Power	
25	Hydraulic Expenses	
26	Electric Expenses	
27	Misc Hydraulic Power Generation Expenses	
28	Rents	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Hydraulic Plant	
34	Total Production Expenses (total 23 thru 33)	
35	Expenses per net kWh	

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	0
12	**Cost of Plant**	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total Cost (10-23)	
22	Cost per KW of installed cap (line 21 / 4)	
23	**Production Expenses**	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per kWh (line 37 / 9)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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, pumped storage plants, and renewable 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.
3. List plants appropriately under subheadings for steam, hydro, nuclear, renewable, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
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.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
1	Oakdale	1925	9.20	5.2	2,135,000	56,912,562	6,186,148				hydro		
2	Norway	1923	7.20	0.0	12,035,000	53,800,545	7,472,298				hydro		

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) and (b) report the name of the energy storage project and location.
3. In column (c), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In column (d) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (c) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In column (e) report MWHs lost during conversion, storage and discharge of energy.
6. In column (f) report the MWHs sold.
7. In column (g), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (h), report the 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. In columns (i) and (j), report fuel costs for storage operations associated with self-generated power and other costs associated with self-generated power.
9. In column (l) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Location of the Project (b)	MWHs (c)	MWHs delivered to the grid (d)	MWHs Lost During Conversion, Storage and Discharge of Energy (e)	MWHs Sold (f)	Revenues from Energy Storage Operations (g)	Power Purchased for Storage Operations (555.1) (Dollars) (h)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (i)	Other Costs Associated with Self-Generated Power (Dollars) (j)	Account for Project Costs (k)	Total Project Plant Costs (l)
1	Cavalry Solar	Indiana	95,749	83,252	13,170	83,252	4,468,844				387	63,414,532
2	Dunn's Bridge 2 Solar	Indiana	125,852	113,289	16,972	113,289	5,710,899				387	107,215,292
35	TOTAL		221,601	196,541	30,142	196,541	10,179,743	0	0	0		170,629,824

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report End of: 2025/ Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a) and (b) report the name of the energy storage project, and location.
3. In column (c), 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.
4. In column (d), report operation expenses excluding fuel, (e), maintenance expenses, (f) fuel costs for storage operations and (g) 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 (h) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Location of the Project (b)	Project Cost (c)	Plant Operating Expenses: Operations (Excluding Fuel used in Storage Operations) (d)	Plant Operating Expenses: Maintenance (e)	Plant Operating Expenses: Cost of fuel used in storage operations (f)	Plant Operating Expenses: Account No. 555.1, Power Purchased for Storage Operations (g)	Plant Operating Expenses: Other Expenses (h)
1								
2								
36	TOTAL		0	0	0	0	0	0

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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 g voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
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. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. 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 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
5. 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 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 are included in the expenses reported for the line designated.
6. 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 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).
7. 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 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 (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 affec lessor, co-owner, or other party is an associated company.
8. 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.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

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	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEP TA	
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintena Expens
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Reynolds	Pioneer Sign IN	765	765	steel tower	21.34		1	795 MCM ACSR					
2	Dumont (AEP)	Stillwell Sub.	345	345	steel tower	2.86		1	2156 MCM ACSR					
3	Dune Acres Sub.	Babcock Sub.	345	345	steel tower	7.71		1	2156 MCM ACSR					
4	Babcock Sub.	Lake George Sub.	345	345	steel tower	11.74		1	2156 MCM ACSR					
5	Munster Sub.	Burnham (CECO)	345	345	steel pole	0.47		1	2156 MCM ACSR					
6	Munster Sub. - a	Burnham (CECO) - a			steel tower	0.15								
7	Michigan City Gen. Station	Babcock Sub.	345	345	steel pole	1.23		1	2156 MCM ACSR					
8	Michigan City Gen Station - a	Babcock Sub. - a			steel tower	18.13								
9	Michigan City Gen. Station	Dune Acres Sub.	345	345	steel pole	8.64	1.23	1	2156 MCM ACSR					
10	Michigan City Gen Station - a	Dune Acres Sub. -a			steel tower	1.76								
11	Schahfer Gen. Station	Tower Road Sub.	345	345	steel tower	19.86		1	2156 MCM ACSR					
12	Schahfer Gen. Station	Lake George Sub.	345	345	steel tower	31.87		1	2156 MCM ACSR					
13	Burr Oak Sub.	Leesburg Sub.	345	345	steel tower	28.16		1	2156 MCM ACSR					
14	Dune Acres Sub.	Gary Avenue	345	345	steel pole	13.88		1	2156 MCM ACSR					
15	Dune Acres Sub. - a	Gary Avenue - a			steel tower	13.09								
16	Sheffield Sub.	State Line Gen. Sta. (CECO)	345	345	steel pole	0.47		1	2156 MCM ACSR					
17	Sheffield Sub. - a	State Line Gen. Sta. (CECO) - a			steel tower	1.41								
18	Sheffield Sub.	Burnham (CECO)	345	345	steel pole	0.46		1	2156 MCM ACSR					
19	Sheffield Sub. - a	Burnham (CECO) - a			steel tower		1.41							
20	Schahfer Gen. Station	Burr Oak Sub.	345	345	steel pole	32.46		1	2156 MCM ACSR					

21	Babcock Sub.	Stillwell Sub.	345	345	steel tower	21.37	7.40	1	900 MCM ACSR					
22	Schahfer Gen. Station	Green Acres Sub.	345	345	steel tower	0.88	25.75	1	2156 MCM ACSR					
23	Leesburg Sub.	Deedsville (CINERGY)	345	345	steel tower	17.68		1	954 MCM ACSR					
24	Sheffield Sub.	Gary Avenue	345	345	steel pole	5.90	1.74	1	2156 MCM ACSR					
25	Schahfer Gen. Station	St. John Sub.	345	345	steel pole	16.00		1	2156 MCM ACSR					
26	Schahfer Gen. Station - a	St. John Sub. - a			steel tower	15.01								
27	Lake George Sub.	Munster Sub.	345	345	steel pole	3.24	8.23	1	2156 MCM ACSR					
28	Lake George Sub. - a	Munster Sub. - a			steel tower	3.28								
29	Tower Road	Babcock Sub.	345	345	steel tower	6.97		1	2156 MCM ACSR					
30	Leesburg Sub.	Hiple, F. G. Sub.	345	345	steel pole	22.66		1	2156 MCM ACSR					
31	Reynolds	Burr Oak Sub.	345	345	steel pole	47.39		1	954 MCM ACSR					
32	Burr Oak	Hiple, F G Sub.	345	345	steel pole	52.23		1	954 MCM ACSR					
33	Praxair Inc #6 - Whiting E	Whting Clean Energy, Inc	138	138	steel pole	0.83		1	2156 MCM ACSR					
34	Batavia (METC)	Barton Lake Sub.	138	138	wood pole	0.96		1	900 MCM ACSR					
35	State Line Gen. Sta. (CECO)	Wolf Lake Sub.	138	138	steel tower	0.09		1	336 ACSR					
36	State Line Gen. Sta. (CECO) - a	Wolf Lake Sub. - a			steel pole	0.91			900 MCM ACSR					
37	State Line Gen. Sta. (CECO) - b	Wolf Lake Sub. - b							954 KCM ACSR					
38	Sheffield Sub.	Calumet	138	138	steel tower	2.40		1	900 MCM ACSR					
39	Aetna Sub.	Dune Acres Sub.	138	138	steel tower	12.36		1	900 MCM ACSR - a					
40	Aenta Sub. - a	Praxair Inc. #5- Burns Harb.												
41	Aetna Sub.	Dune Acres Sub.	138	138	steel tower	0.40	11.23	1	900 MCM ACSR					
42	Monticello Sub.	SpringBoro (Duke)	138	138	steel tower	4.40		1	900 MCM ACSR					
43	Monticello Sub. - a	SpringBoro (Duke) - a			wood H-frame	6.59								
44	Roxana Sub.	mittal Steel IN Harbor #2	138	138	steel pole	0.24		1	300 MCM CU					
45	Roxana Sub. - a	mittal Steel IN Harbor #2 - a			steel tower	3.81			400 MCM CU					
46	Hiple, F. G. Sub.	LaGrange Sub.	138	138	wood pole	13.29		1	900 MCM ASCR					
47	Burns Ditch Sub.	Miller Sub.	138	138	steel tower	8.01		1	900 MCM ASCR					
48	Chicago Ave. Sub.	Praxair Inc. #1-	138	138	steel pole	0.24		1	900 MCM ASCR					
49	Chicago Ave. Sub. - a	East Chicago	138	138	wood pole	2.21		1						
50	Maple Sub.	LNG Plant	138	138	steel tower	7.08		1	300 MCM CU					
51	Maple Sub. - a	LNG Plant - a			wood pole	0.73			336.4 MCM ACSR					
52	Maple Sub. - b	LNG Plant - b							397.5 MCM ACSR					

53	Michigan City Gen. Station	LaPorte Jct (AEP)	138	138	steel tower	22.79		1	397.5 MCM ACSR					
54	Michigan City Gen. Station - a	Olive (AEP)	138	138				1						
55	Michigan City Gen. Station	Trail Creek	138	138	steel tower	0.26	6.25	1	397.5 MCM ACSR					
56	Michigan City Gen. Station	Luchtman Rd. Sub.	138	138	steel tower	5.04		1	300 MCM CU					
57	Michigan City Gen. Station - a	Luchtman Rd. Sub. - a			wood pole	0.02								
58	New Carlisle Sub.	Maple Sub.	138	138	steel pole	5.29	9.82	1	300 MCM CU					
59	New Carlisle Sub. - a	Maple Sub. - a							397.5 MCM ACSR					
60	Miller Sub.	US Steel - Tin Mill	138	138	steel tower	4.87		1	900 MCM ACSR					
61	Aetna Sub.	Praxair Inc. #3-Lakeside	138	138	steel tower	7.41		1	400 MCM CU					
62	Aetna Sub. - a	Praxair Inc. #3-Lakeside - a							900 MCM ACSR					
63	Burr Oak Sub.	Plymouth Sub.	138	138	steel tower	8.14		1	949 MCM ACSR					
64	Burr Oak Sub. - a	Plymouth Sub. - a			wood pole	0.10			300 MCM CU					
65	Burr Oak Sub. - b	Plymouth Sub. - b							397.5 MCM ACSR					
66	Valparaiso	Starke	138	138	steel tower	15.30		1	397.5 MCM ACSR					
67	Plymouth Sub.	Kosciusko Sub.	138	138	steel tower	20.10	2.24	1	336.4 MCM ACSR					
68	Plymouth Sub. - a	Leesburg Sub.	138	138	wood pole	7.78		1	397.5 MCM ACSR					
69	Plymouth Sub. - b	Northwest-Kosciusko Co	138	138				1	900 MCM ACSR					
70	Lake George Sub.	Miller Sub.	138	138	steel tower	5.49		1	900 MCM ACSR					
71	Munster Sub.	Hartsdale Sub.	138	138	steel pole	2.63		1	397.5 MCM ACSR					
72	Munster Sub. - a	Hartsdale Sub. - a			wood H-frame	2.64			900 MCM ACSR - a					
73	Marktown	Whiting Clean Energy, INC	138	138	steel pole	1.00		1	2156 MCM ACSR					
74	Mitchell Gen. Station	Roxana Sub.	138	138	steel pole	0.09		1	3158 KCM AL					
75	Mitchell Gen. Station - a	Roxana Sub. - a			steel tower	4.08			900 MCM ACSR - a					
76	Mitchell Gen. Station - b	Roxana Sub. - b			underground	0.57			400 MCM CU					
77	Mitchell Gen. Station	US Steel - Tin Mill	138	138	steel tower	3.29	1.20	1	900 MCM ACSR					
78	Michigan City Gen. Station	Maple Sub.	138	138	steel tower	12.29	4.76	1	900 MCM ACSR					
79	DeKalb Sub.	Auburn (AEP)	138	138	wood H-frame	5.01		1	397.5 MCM ACSR					
80	Chicago Ave. Sub.	Mittal Steel IN Harbor #5	138	138	steel tower	2.01		1	900 MCM ACSR					
81	Marktown Sub.	Mittal Steel IN Harbor #5	138	138	steel pole	0.13		1	954 MCM ACSR					
82	Marktown Sub. - a	Mittal Steel IN Harbor #5 - a			steel tower	1.65								

83	Chicago Ave. Sub.	Praxair Inc. #3-Lakeside	138	138	steel tower	1.43	0.18	1	400 MCM CU					
84	Chicago Ave. Sub. - a	Praxair Inc. #3-Lakeside - a							900 MCM ACSR					
85	East Winamac Sub.	Monticello Sub.	138	138	steel tower	24.08		1	300 MCM ACSR					
86	Chicago Ave. Sub.	Mittal Steel IN Harbor #7	138	138	steel tower	0.34	2.40	1	900 MCM ACSR					
87	St John	Enbridge - Griffith Term E	138	138	steel pole	5.40		1	900 MCM ACSR					
88	Roxana Sub.	Praxair Inc. #1-	138	138	steel tower	0.17	2.05	1	300 MCM CU					
89	Roxana Sub. - a	East Chicago							400 MCM CU					
90	Roxana Sub. - b	East Chicago - a							900 MCM CU					
91	Dune Acres Sub.	Burns Ditch Sub.	138	138	steel tower	4.13		1	900 MCM ACSR					
92	Michigan City Gen. Station	Dune Acres Sub.	138	138	steel tower	11.65		1	300 MCM CU					
93	Michigan City Gen. Station - a	Dune Acres Sub. - a							397.5 MCM ACSR					
94	Marktown Sub.	Mittal Steel IN Harbor #2	138	138	steel tower	0.50		1	954 KCM ACSR					
95	Miller Sub.	Beta Steel Arc Furnace	138	138	steel pole	0.35		1	900 MCM ACSR					
96	Miller Sub. - a	Beta Steel Arc Furnace - a			steel tower	0.37	8.29							
97	Michigan City Gen. Station	Dune Acres Sub.	138	138	steel tower	0.91	10.73	1	300 MCM CU - a					
98	Michigan City Gen. Station - b	Dune Acres Sub. - b							900 MCM ACSR					
99	Northeast Sub.	Leesburg Sub.	138	138	steel tower	9.93		1	397.5 MCM ACSR					
100	Northeast Sub. - a	Leesburg Sub. - a							900 MCM ACSR					
101	Mitchell Gen. Station	Mitchell Gen. Station	138	138	steel tower	0.10		1	900 MCM ACSR					
102	Monticello	Magnetation	138	138	steel pole	0.40		1	900 MCM ACSR					
103	Monticello - a	Magnetation - a			steel tower	5.59			954 MCM ASCR					
104	Dune Acres Sub.	Mittal Steel Burns Harbor	138	138	steel tower	1.17	1.17	1	1590 MCM ACSR					
105	Marktown Sub.	Mittal Steel IN Harbor #3-4	138	138	steel tower	0.23		1	900 MCM ACSR					
106	Schahfer Gen. Station	Jasper Co ROMC.	138	138	wood pole	19.62		1	336.4 MCM ACSR					
107	Schahfer Gen. Station - a	Jasper Co ROMC. - a							397.5 MCM ACSR					
108	Trail Creek Sub.	LaPorte-St. Joseph Co. Line	138	138	steel tower	0.22	12.75	1	397.5 MCM ACSR					
109	Trail Creek Sub. - a	Jct. W/AEP EL CO			wood pole	3.17								
110	State Line Gen. Sta. (CECO)	Roxana Sub.	138	138	steel tower	5.58	1.97	1	900 MCM ACSR					
111	State Line Gen. Sta. (CECO) - a	Roxana Sub. - a							300 MCM CU					
112	Aetna Sub.	Lake George Sub.	138	138	steel tower		4.95	1	900 MCM ACSR					
113	Northport Sub.	Albion (AEP)	138	138	steel tower	10.42		1	397.5 MCM ACSR					

114	Goodland Sub.	Reynolds Sub.	138	138	steel tower	17.72		1	397.5 MCM ACSR					
115	Goodland Sub. - a	Reynolds Sub. - a			wood pole	4.31			900 MCM ACSR - a					
116	Marktown Sub.	Mittal Steel IN.Harbor-No7			steel tower	0.83			900 MCM ACSR					
117	Chicago Ave. Sub.	US Steel - Stockton			steel tower	0.22	1.93		900 MCM ACSR					
118	Chicago Ave. Sub. - a	US Steel - Stockton - a							400 MCM CU					
119	Mitchell Gen. Station	US Steel - Coke Plant	138	138	steel tower	0.64	4.97	1	900 MCM ACSR					
120	Aetna Sub.	US Steel - West Mill	138	138	steel tower	0.65	3.17	1	900 MCM ACSR					
121	Aenta Sub. - a	US Steel - West Mill - a							400 MCM CU					
122	Lake George Sub.	Taney Sub.	138	138	steel pole	3.37		1	2156 MCM ACSR					
123	Lake George Sub. - a	Taney Sub. - a			steel tower	2.90			900 MCM ACSR - b					
124	Lake George Sub. - b	Taney Sub. - b			wood pole	0.12								
125	Lake George Sub.	Highland Sub.	138	138	steel pole	4.82	3.37	1	2156 MCM ACSR					
126	Lake George Sub. - a	Highland Sub. - a			steel tower		2.84		900 MCM ACSR - a					
127	Hendricks Sub.	US Steel - Stockton	138	138	steel tower	0.04	1.48	1	400 MCM CU					
128	Hendricks Sub. - a	US Steel - Stockton - a							900 MCM ACSR					
129	Miller Sub.	US Steel - Coke Plant	138	138	steel pole	0.06		1	900 MCM ACSR					
130	Miller Sub. - a	US Steel - Coke Plant - a			steel tower	0.19	2.09							
131	Lake George Sub.	Tower Road Sub.	138	138	steel tower	5.93		1	2156 MCM ACSR					
132	Lake George Sub. - a	Tower Road Sub. - a			wood H-frame	8.06			900 MCM ACSR - b					
133	Lake George Sub. - b	Tower Road Sub. - a							397.5 MCM ACSR					
134	Lake George Sub.	Liberty Park Sub.	138	138	steel tower	5.90		1	397.5 MCM ACSR					
135	Lake George Sub. - a	Liberty Park Sub. - a			wood H-frame	5.86			900 MCM ACSR - c					
136	St. John Sub.	Liberty Park Sub.	138	138	wood H-frame	2.01		1	397.5 MCM ACSR					
137	St. John Sub. - a	Liberty Park Sub. - a			wood pole	0.22								
138	Marktown Sub.	BP Whiting Refinery	138	138	steel pole	0.87		1	900 MCM ACSR					
139	Roxana Sub.	Calumet Sub.	138	138	steel tower	0.42	2.04	1	900 MCM ACSR					
140	Morrison Ditch	Sheldon South	138	138	wood pole	1.88		1	900 MCM ACSR					
141	Morrison Ditch - a	Sheldon South - a							954 MCM ACSR					
142	Tower Road Sub.	Flint Lake Sub.	138	138	steel tower	5.55		1	954 MCM ACSR					
143	Flint Lake Sub.	Luchtman Rd. Sub.	138	138	steel tower	11.75		1	397.5 MCM ACSR					
144	Flint Lake Sub. - a	Luchtman Rd. Sub. - a			wood pole	0.85								

145	Schahfer Gen. Station	Schahfer Gen. Construction	138	138	steel tower	3.06		1	397.5 MCM ACSR					
146	Schahfer Gen. Station - a	Starke Sub.			wood pole	25.89								
147	Schahfer Gen. Station - b	Thayer Sub.												
148	Dune Acres	Babcock Sub.	138	138	steel pole	0.35		1	900 MCM ACSR					
149	Dune Acreas - a	Babcock Sub. - a			steel tower		7.36							
150	Sheffield Sub.	BP Whiting Refinery	138	138	steel pole	1.57		1	900 MCM ACSR					
151	Sheffield Sub.	Marktown Sub.	138	138	steel pole	0.47	1.91	1	900 MCM ACSR					
152	Dune Acres Sub.	Beta Steel Arc Furnace	138	138	steel pole	0.37		1	900 MCM ACSR					
153	Dune Acres Sub. - a	Beta Steel Arc Furnace - a			steel tower		3.46							
154	Northeast Sub.	Goshen Jct. Sub.	138	138	wood pole	8.78		1	900 MCM ACSR					
155	Kosciusko Sub.	Leesburg Sub.	138	138	steel tower	5.07	1.19	1	397.5 MCM ACSR					
156	Kosciusko Sub. - a	Leesburg Sub. - a			wood pole	1.17			900 MCM ACSR - b					
157	Burr Oak Sub.	East Winamac Sub.			steel tower	15.57			954 MCM ACSR					
158	Burr Oak Sub. - a	East Winamac Sub. - a							300 MCM CU					
159	Burr Oak Sub. - b	East Winamac Sub. - b							397.5 MCM ACSR					
160	South Prairie Sub.	Westwood (Duke)	138	138	wood pole	17.24		1	397.5 MCM ACSR					
161	Dune Acres Sub.	Praxair Inc. #5-Burns Harb.	138	138	steel tower	0.02	2.60	1	900 MCM ACSR					
162	Lake George Sub.	Ainsworth Sub.	138	138	steel tower	0.27	5.04	1	900 MCM ACSR					
163	Lake George Sub. - a	Green Acres Sub.												
164	Schahfer Gen. Station	Tower Road Sub.	138	138	steel pole	0.36		1	2156 MCM ACSR					
165	Schahfer Gen. Station - a	Tower Road Sub. - a			steel tower	0.40	21.90		900 MCM ACSR - c					
166	LaGrange Sub.	Northport Sub.	138	138	steel tower	8.47		1	397.5 MCM ACSR					
167	Green Acres Sub.	St. John Sub.	138	138	concrete pole	4.01		1	900 MCM ACSR					
168	Green Acres Sub. - a	St. John Sub. - a			steel pole	3.75			954 MCM ACSR					
169	Green Acres Sub. - b	St. John Sub. - b			wood pole	0.78								
170	Hendricks Sub.	US Steel - West Mill	138	138	steel tower	0.06	2.43	1	400 MCM CU					
171	Hendricks Sub. - a	US Steel - West Mill - a							900 MCM ACSR					
172	Chicago Ave. Sub.	Mittal Steel IN Harbor-No8	138	138	steel pole	0.90		1	900 MCM ACSR					
173	Chicago Ave. Sub. - a	Mittal Steel IN Harbor-No8 - a			steel tower	1.04								
174	Mitchell Gen. Station	Mittal Steel IN Harbor-No8	138	138	steel pole	0.94		1	900 MCM ACSR					

175	Mitchell Gen. Station - a	Mittal Steel IN Harbor-No8 - a			steel tower	0.16	1.94							
176	Mitchell Gen. Station	Chicago Ave. Sub.	138	138	steel tower	0.33	0.93	1	900 MCM ACSR					
177	Wolf Lake Sub.	Sheffield Sub.	138	138	steel tower	1.92	0.59	1	336 ACSS					
178	Wolf Lake Sub. - a	Sheffield Sub. - a			wood pole	0.19			954 KCM ACSS					
179	Munster Sub.	Kenwood Sub.	138	138	steel pole	1.68	2.13	1	900 MCM ACSR					
180	Munster Sub. - a	Kenwood Sub. - a			steel tower	2.67			300 MCM CU					
181	Munster Sub. - b	Kenwood Sub. - b			wood pole	0.21								
182	Munster Sub.	Taney Sub.	138	138	steel pole		8.48	1	2156 MCM ACSR					
183	Munster Sub. - a	Taney Sub. - a			wood pole	0.11			900 MCM ACSR - c					
184	Plymouth Sub.	Stillwell Sub.	138	138	steel tower	19.27		1	300 MCM CU					
185	Plymouth Sub. - a	Stillwell Sub. - a			wood pole	1.25			954 MCM ACSR					
186	Stillwell Sub.	LNG Plant	138	138	steel tower	7.07		1	300 MCM CU					
187	Stillwell Sub. - a	LNG Plant - a			wood pole	0.73			336.4 MCM ACSR					
188	Tower Road Sub.	Babcock Sub.	138	138	steel pole	0.14		1	2156 MCM ACSR					
189	Tower Road Sub. - a	Babcock Sub. - a			steel tower		4.06		900 MCM ACSR					
190	Tower Road Sub. - b	Babcock Sub. - b			wood pole	0.14								
191	Highland Sub.	Kenwood Sub.	138	138	steel pole	0.33	2.70	1	900 MCM ACSR					
192	St. John Sub.	Kreitzburg Sub.	138	138	concrete pole	2.44		1	2156 MCM ACSR					
193	St. John Sub. - a	Kreitzburg Sub. - a				0.39	2.18		900 MCM ACSR					
194	Aetna Sub.	Miller Sub.	138	138	steel tower	0.20	0.33	1	900 MCM ACSR					
195	Hiple, F. G. Sub.	Goshen Jct. Sub.	138	138	wood pole	16.10		1	900 MCM ACSR					
196	Gary Avenue	Chicago Ave	138	138	steel pole	0.20		1	3158 KCM AL					
197	Gary Avenue - a	Chicago Ave - a			underground	0.57			900 MCM ACSR					
198	Goodland	Morrison Ditch			wood pole	12.32			900 MCM ACSR					
199	Goodland - a	Morrison Ditch - a							954 MCM ACSR					
200	Tower Road	Flint Lake	138	138	steel pole	5.57		1	954 MCM ACSR					
201	Marktown	Praxair INC #6-Whiting East	138	138	steel pole	0.19		1	2156 MCM ACSR					
202	Hartsdale	Enbridge - Griffith Term E	138	138	steel pole	1.23		1	900 MCM ACSR					
203	Reynolds	Magnetation	138	138	steel pole	0.42		1	900 MCM ACSR					
204	Reynolds - a	Magnetation - a			steel tower	0.36			954 MCM ACSR					
205	Flint Lake	Valparaiso	138	138	steel tower	6.09		1	397.5 MCM ACSR					
206	Flint Lake - a	Valparaiso - a												
207	Bailly Gen. Sta. - Unit 7	Dune Acres Sub.	138	138	steel tower	1.55		1	900 MCM ACSR					

208	Bailly Gen. Sta. - Unit 8	Dune Acres Sub.	138	138	steel tower	1.52		1	1590 MCM ACSR					
209	Bailly Gen. Sta. - R.A.T.	Dune Acres Sub.	138	138	steel tower	1.50		1	900 MCM ACSR					
210	Roxana Sub.	Steel Pole #9126(138501)	138	138	steel pole	0.10	1.04	1	900 MCM ACSR					
211	Roxana Sub. - a	Steel Pole #9126(138501) - a			steel tower	0.22								
212	Roxana Sub.	Tower #4068(138702)	138	138	steel tower	1.41		1	900 MCM ACSR					
213	Marktown Sub	Tower #246(138703)	138	138	steel tower	0.21		1	400 MCM CU					
214	Tap to Mittal Steel #8	CokeEnergy (O/S 3/8/00)	138	138	steel tower	1.27		1	336.4 MCM ACSR					
215	69KV									1,655,110	462,084,296	463,739,406		
216	138KV									12,456,981	352,708,772	365,165,753		
217	345KV									44,900,467	443,709,062	488,609,529		
218	765KV									30,964,301	56,486,519	87,450,820		
36	TOTAL					1,012.36	217.92	134		89,976,859.00	1,314,988,649.00	1,404,965,508.00	0.00	0

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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 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.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Circuit 34514												4,502,204	4,502,204		9,004,408	
2	Circuit 6915												3,781,569	4,376,835		8,158,404	
3	Circuit 6950												6,372,693	1,020,435		7,393,128	
4	Circuit 6918												4,551,106	(3)		4,551,103	
5	Circuit 06921												2,415,102	1,640,446		4,055,548	
6	Circuit 6943												4,052,179			4,052,179	
7	Circuit 6923												1,863,948	1,863,948		3,727,896	
8	Circuit 6974												1,863,948	1,863,948		3,727,896	
9	Circuit 6976												2,876,860	168,483		3,045,343	
10	Circuit 6928												1,545,069	1,294,861		2,839,930	
11	Circuit 6935												1,174,733	1,458,654		2,633,387	
12	Circuit 13821												1,989,164	252,815		2,241,979	
13	Circuit 13800													1,789,655		1,789,655	
14	Circuit 6985												210,029	908,658		1,118,687	
44	TOTAL		0		0	0	0						37,198,604	21,140,939		58,339,543	

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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).
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.

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	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)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
1	Reynolds - White - Honey Creek TWP	Transmission	Unattended	765	345		3000	3	1			
2	Burr Oak - Marshall - Union	Transmission	Unattended	345	138	14	560	1	0			
3	Dune Acres - Porter - Dune Acres_a	Transmission	Unattended	345	138	14	560	1	0			
4	Dune Acres - Porter - Dune Acres_b	Transmission	Unattended	138	34		224	2	0	Capacitors	1	108,000
5	Gary Avenue - Lake - Gary	Transmission	Unattended	345	138	14	860	2	1			
6	Hiple, FG - Lagrange - Eden Twp_a	Transmission	Unattended	345	138	14	480	1	0	Capacitors	2	8,000
7	Hiple, FG - Lagrange - Eden Twp_b	Transmission	Unattended	138	69	14	224	2	0			
8	Lake George - Lake - Hobart_a	Transmission	Unattended	138	69		224	2	0	Capacitors	2	6,480
9	Lake George - Lake - Hobart_b	Transmission	Unattended	345	138		1120	2	0			
10	Lake George - Lake - Hobart_c	Transmission	Unattended	138	69		224	2	0	Capacitors	3	27,000
11	Leesburg - Kosciusko - Prairie_a	Transmission	Unattended	138	69		168	1	0			
12	Leesburg - Kosciusko - Prairie_b	Transmission	Unattended	345	138	14	560	1	0	Capacitors	2	8,640
13	Michigan City Gen Sta - Laporte - Michigan City _a	Transmission	Attended	345		21	616	1	0			
14	Michigan City Gen Sta - Laporte - Michigan City_b	Transmission	Attended	138	34	14	60	1	0			
15	Michigan City Gen Sta - Laporte - Michigan City _c	Transmission	Attended	138	34	12	60	3	0			
16	Michigan City Gen Sta - Laporte - Michigan City_d	Transmission	Attended	138		14	168	2	0			
17	Munster - Lake - Munster_a	Transmission	Unattended	345	138	14	560	1	0			
18	Munster - Lake - Munster_b	Transmission	Unattended	138	34		224	2	0			
19	Reynolds - White - Honey Creek Twp	Transmission	Unattended	345	138	14	350	1	0			
20	Schahfer Gen Sta - Jasper - Kankakee Twp_a	Transmission	Attended	345	138	14	336	1	0	Step Voltage Reg	1	70,000
21	Schahfer Gen Sta - Jasper - Kankakee Twp_b	Transmission	Attended	345		23	918	2				
22	Schahfer Gen Sta - Jasper - Kankakee Twp_c	Transmission	Attended	345		21	616	1				
23	Schahfer Gen Sta - Jasper - Kankakee Twp_d	Transmission	Attended	345		17	600	1				
24	Schahfer Gen Sta - Jasper - Kankakee Twp_e	Transmission	Attended	138		14	224	2	0			
25	Sheffield - Lake - Hammond	Transmission	Unattended	345	138	14	500	1	0			
26	St John - Lake - St John Twp_a	Transmission	Unattended	345	138	14	436	3	0			
27	St John - Lake - St John Twp_b	Transmission	Unattended	138		12	28	1	0			
28	Stillwell - Laporte - Lincoln Twp_a	Transmission	Unattended	345	138	14	336	1	0			
29	Stillwell - Laporte - Lincoln Twp_b	Transmission	Unattended	138	69		67	1	0			
30	Sugar Creek Gen Sta - Vigo - West Terre Haute	Transmission	Attended	345		18	717	3				
31	Tower Road - Porter - Center	Transmission	Unattended	345	138	14	350	1	0			
32	Aetna - Lake - Gary	Transmission	Unattended	138	34		224	2	0	Capacitors	4	19,800
33	Ainsworth - Lake - Ross Twp	Transmission	Unattended	138	12		28	1	0			

34	Babcock - Porter - Liberty Twp_a	Transmission	Unattended	138	69		280	2	0			
35	Babcock - Porter - Liberty Twp_b	Transmission	Unattended	69	12		56	2	0			
36	Baily Gen Station - Porter - Westchester Twp_a	Transmission	Attended	138		14	45	1	0	Excitation Xfr	1	1,846
37	Baily Gen Station - Porter - Westchester Twp_b	Transmission	Attended	138		21	773	2	0	Excitation Xfr	1	12,754
38	Barton Lake - Steuben - James Twp	Transmission	Unattended	138	69		294	3	0			
39	Beta Steel Arc Furnace - Porter - Burns Harbor	Transmission	Unattended	138	34		224	2	0			
40	Burns Ditch - Porter - Portage	Transmission	Unattended	138	34		112	1	0			
41	Calumet - Lake - Hammond	Transmission	Unattended	138	34		168	2	0			
42	Chicago Ave - Lake - Gary	Transmission	Unattended	138	0		0	0	0			
43	Dekalb - Dekalb - Grant Twp	Transmission	Unattended	138	69	13	45	1	0			
44	East Winamac - Pulaski - Monroe Twp	Transmission	Unattended	138	69		224	2	0	Capacitors	3	16,200
45	Eagle Creek - Starke - Center	Transmission	Unattended	69						Capacitors	3	16,200
46	Enbridge - Griffith Terminal East - Lake - Griffith	Transmission	Unattended	138	138		59	2	0			
47	Flint Lake - Porter - Washington Twp_a	Transmission	Unattended	138	69		336	2	0	Capacitors	3	32,400
48	Flint Lake - Porter - Washington Twp_b	Transmission	Unattended	138	12		36	1	0			
49	Flint Lake - Porter - Washington	Transmission	Unattended	69	12		28	1	0	Capacitors	6	64,800
50	Goodland - Newton - Grant Twp	Transmission	Unattended	138	69		224	2	0	Capacitors	4	25,200
51	Goshen Jct - Elkhart - Elhart Twp	Transmission	Unattended	138	69		336	2	0	Capacitors	3	32,400
52	Grand Army - Marshall - German	Transmission	Unattended	69				0	0	Capacitors	2	
53	Green Acres - Lake - Ross Twp	Transmission	Unattended	138	69		336	3	1	Capacitors	4	43,200
54	Hartsdale - Lake - Highland_a	Transmission	Unattended	138	69		224	2	0	Capacitors	3	32,400
55	Hartsdale - Lake - Highland_b	Transmission	Unattended	138	12		90	2	0			
56	Hendricks - Lake - Gary	Transmission	Unattended	138	34		56	1	0			
57	Highland - Lake - Highland_a	Transmission	Unattended	138	34		224	2	0	Capacitors	4	32,400
58	Highland - Lake - Highland_b	Transmission	Unattended	138	12		28	1	0			
59	Kenwood - Lake - Hammond	Transmission	Unattended	138	34		224	2	0	Capacitors	2	16,200
60	Kosciusko - Kosciusko - Wayne Twp	Transmission	Unattended	138	69		336	2	0	Capacitors	3	32,400
61	Kreitzburg - Lake - Hanover Twp	Transmission	Unattended	138	69		112	1	0			
62	L.N.G. Plant - Laporte - Rolling Prairie	Transmission	Attended	138		4	56	2	0			
63	Lagrange - Lagrange - Lagrange	Transmission	Unattended	138	69		336	2	0	Capacitors	2	12,600
64	Liberty Park - Lake - Center Twp_a	Transmission	Unattended	138	69		336	2	0	Capacitors	4	23,200
65	Liberty park - Lake - Center Twp_b	Transmission	Unattended	69	12		56	2	0			
66	Lutchman Rd - Laporte - Coolspring Twp_a	Transmission	Unattended	138	69		112	1	0			
67	Lutchman Rd - Laporte - Coolspring Twp_b	Transmission	Unattended	69	12		22	1	0			
68	Magnetation - White - Reynolds	Transmission	Unattended	138	69		112	1	0			
69	Maple - Laporte - Center_a	Transmission	Unattended	138	69		224	2	0	Capacitors	2	16,200
70	Maple - Laporte - Center_b	Transmission	Unattended	69	12		28	1				
71	Marktown - Lake - East Chicago_a	Transmission	Unattended	138	34	12	112	2	0	Capacitors	2	16,200
72	Marktown - Lake - East Chicago_b	Transmission	Unattended	138	34		112	1	0			
73	Marktown - Lake - East Chicago_c	Transmission	Unattended	34	12		14	1	0			
74	Miller - Lake - Gary	Transmission	Unattended	138								
75	Mitchell Gen Sta - Lake - Gary_a	Transmission	Unattended	138	34	14	116	2	0			
76	Mitchell Gen Sta - Lake - Gary_b	Transmission	Unattended	138		15	560	4	0			
77	Mitchell Gen Sta - Lake - Gary_c	Transmission	Unattended	34		13	64	1	0			
78	Monticello - White - Monticello_a	Transmission	Unattended	138	69	34	224	2	0			
79	Monticello - White - Monticello_b	Transmission	Unattended	69	12	34	44	2	0	Capacitors	4	43,200
80	Morrison Ditch - Newton - Jefferson	Transmission	Unattended	138								
81	Northeast - Elkhart - Jackson Twp	Transmission	Unattended	138	69		224	2	0	Capacitors	6	64,800
82	Northport - Noble - Elkhart	Transmission	Unattended	138	69		100	1	0	Capacitors	3	16,200
83	Norway Hydro - White - Union Twp	Transmission	Unattended	69	2		11	1	0			

84	Oakdale Hydro - Carroll - Jefferson Twp_a	Transmission	Unattended	69	12		5	1	0	Step Volt Reg	3	750
85	Oakdale Hydro - Carroll - Jefferson Twp_b	Transmission	Unattended	69		2	16	2	0			
86	Plymouth - Marshall - Plymouth_a	Transmission	Unattended	138	69		336	2	0			
87	Plymouth - Marshall - Plymouth_b	Transmission	Unattended	69	12		56	2	0	Capacitors	5	54,000
88	Roxana - Lake - East Chicago_a	Transmission	Unattended	138	34		224	1	0			
89	Roxana - Lake - East Chicago_b	Transmission	Unattended	34	12		56	2	0			
90	Schrader Ditch - Kankakee - Jasper	Transmission	Unattended	138			225	1	1			
91	South Prairie - White - Prairie Twp	Transmission	Unattended	138	69		168	2	0			
92	South Valparaiso - Porter - Valparaiso	Transmission	Unattended	138	69		336	2	0			
93	Starke - Starke - Railroad Twp_a	Transmission	Unattended	138	69		112	2	0			
94	Starke - Starke - Railroad Twp_b	Transmission	Unattended	69	12		14	2	0	Capacitors	4	25,200
95	Taney - Lake - Gary	Transmission	Unattended	138	69		224	2	0	Capacitors	2	12,600
96	Thayer - Newton - Lincoln_a	Transmission	Unattended	138	69		224	2	0	Capacitors	2	14,400
97	Thayer - Newton - Lincoln_b	Transmission	Unattended	69	12		21	2	0	Step Volt Reg	6	1,998
98	York Ditch - Elkhart - York	Transmission	Unattended	69				0	0	Capacitors	3	32,400
99	Trail Creek - Laporte - Michigan City	Transmission	Unattended	138	34		134	2	0	Capacitors	3	22,500
100	Wolf Lake - Lake - Hammond	Transmission	Unattended	138	34		224	2	0			
101	Angola - Steuben - Angola	Distribution	Unattended	69	12		56	2	0	Capacitors	5	54,000
102	Argos - Marshall - Walnut Twp	Distribution	Unattended	69	12		7	1	0	Step Volt Reg	3	840
103	Ashley - Steuben - Steuben Twp	Distribution	Unattended	69	12		14	1	0	Step Volt Reg	3	1,396
104	Asphaltum - Jasper - Walker Twp	Distribution	Unattended	69	12		11	1	0	Step Volt Reg	3	999
105	Bass Lake - Starke - California Twp	Distribution	Unattended	69	12		25	1	1	Step Volt Reg	2	832
106	Bingo Lake - Lake - St John	Distribution	Unattended	69	12		28	1	0			
107	Bonaire - Lake - Ross Twp_a	Distribution	Unattended	69	12		17	1	0			
108	Bonaire - Lake - Ross Twp_b	Distribution	Unattended	34	12		14	1	0			
109	Bonneyville - Elkhart - York Twp	Distribution	Unattended	69	12		28	1	0	Capacitors	1	5,400
110	Bourbon - Marshall - Bourbon Twp	Distribution	Unattended	69	12		21	2	0	Step Volt Reg	2	746
111	Brighton - Lagrange - Greenfield Twp	Distribution	Unattended	69	12		11	1	0	Step Volt Reg	3	1,119
112	Bristol - Elkhart - Bristol	Distribution	Unattended	69	12		56	2	0			
113	Broadway - Lake - Ross Twp	Distribution	Unattended	69	12		56	2	0			
114	Brook - Newton - Iroquois	Distribution	Unattended	69	12		7	1	0	Step Volt Reg	3	750
115	Bruce Lake - Fulton - Union Twp	Distribution	Unattended	69	12		21	2	0	Step Volt Reg	6	1,998
116	Buchanan St - Lake - Merrillville	Distribution	Unattended	69	69		28	1	0			
117	Buffalo Pike - White - Union Twp	Distribution	Unattended	69	12		11	1	0	Step Volt Reg	3	999
118	Burdick Road - Porter - Pine Twp	Distribution	Unattended	69	12		11	1	0	Step Volt Reg	3	999
119	Burnettsville - White - Burnettsville	Distribution	Unattended	69	12		7	1	0	Step Volt Reg	3	501
120	Buttermilk Corners - Noble - Perry Twp	Distribution	Unattended	69	12		21	2	0	Step Volt Reg	6	2,238
121	Campus - Porter - Valparaiso	Distribution	Unattended	69	12		28	1	0			
122	Cedar Lake - Lake - Center Twp	Distribution	Unattended	69	12		43	2	0			
123	Center - Marshall - Center Twp	Distribution	Unattended	69	12		28	2	0			
124	Chesterton - Porter - Chesterton_a	Distribution	Unattended	69	12		28	1	0			
125	Chesterton - Porter - Chesterton_b	Distribution	Unattended	34	12		28	1	0			
126	Clay - Kosciusko - Clay Twp	Distribution	Unattended	69	12		21	1	1	Step Volt Reg	3	1,119
127	Clunette - Kosciusko - Scott Twp	Distribution	Unattended	69	12		7	1	0	Step Volt Reg		
128	College - Jasper - Marion Twp	Distribution	Unattended	69	12		7	1	0	Capacitors	2	1,200
129	Cornell - Porter - Boone Twp	Distribution	Unattended	69	12		7	1	0	Capacitors	1	5,400

130	Court - Lake - Crown Point	Distribution	Unattended	69	12		56	2	0			
131	Creston - Lake - West Creek Twp	Distribution	Unattended	69	12		56	2	0	Step Volt Reg	3	1,119
132	Crystal Valley - Elkhart - Middlebury	Distribution	Unattended	69	12		11	1	0	Step Volt Reg	3	1,119
133	Culver - Marshall - Culver	Distribution	Unattended	69	12		21	1	1	Step Volt Reg	6	2,118
134	Deep River - Porter - Union Twp	Distribution	Unattended	69	12		28	1	1			
135	Deer Run - Laporte - Washington Twp	Distribution	Unattended	69	12		21	2	0	Step Volt Reg	3	1,119
136	Demotte - Jasper - Keener Twp	Distribution	Unattended	69	12		25	1	0	Step Volt Reg	6	2,796
137	Dierdorff Rd - Elkhart - Elkhart Twp	Distribution	Unattended	69	12		28	1	0			
138	Division - Laporte - Center Twp	Distribution	Unattended	69	12		17	1	0			
139	Donaldson - Marshall - West Twp	Distribution	Unattended	69	12		3	1	0	Step Volt Reg	3	750
140	Dyer - Lake - Dyer_a	Distribution	Unattended	69	12		28	1	0			
141	Dyer - Lake - Dyer_b	Distribution	Unattended	34	12		22	1	0			
142	East Gary - Lake - Lake Station_a	Distribution	Unattended	69	12		22	1	0			
143	East Gary - Lake - Lake Station_b	Distribution	Unattended	34	12		11	1	0			
144	East Walkerton - St Joseph - Walkerton	Distribution	Unattended	69	12		28	2	0	Step Volt Reg	6	2,796
145	Edgewater - Lake - Merrillville	Distribution	Unattended	69	12		28	1	0			
146	Elkhart River - Elkhart - Elkhart Twp	Distribution	Unattended	69	12		28	1	0			
147	Evans - Porter - Valparaiso	Distribution	Unattended	69	12		45	2	0			
148	Fail Road - Laporte - Kankankee Twp	Distribution	Unattended	69	12		14	1	0			
149	Fish Lake - Laporte - Lincoln Twp	Distribution	Unattended	69	12		6	1	0	Step Volt Reg	3	561
150	Fowler - Benton - Fowler	Distribution	Unattended	69	12		17	2		Step Volt Reg	6	1,500
151	Fremont - Steuben - Fremont	Distribution	Unattended	69	12		56	2	0	Capacitors	2	10,800
152	Goodland JCT - Newton - Grant Twp	Distribution	Unattended	69	12		14	2	0	Step Volt Reg	3	750
153	Grand Trunk - Porter - Center	Distribution	Unattended	69	12		28	1	0			
154	Greenway - Laporte - Laporte	Distribution	Unattended	69	12		56	2	0			
155	Guernsey - White - Union Twp	Distribution	Unattended	69	12		14	2	0	Step Volt Reg	6	1,590
156	Hager - Lake - Cedar Lake	Distribution	Unattended	69	12		28	1	0			
157	Hamlet - Starke - Oregon	Distribution	Unattended	69	12		14	2	0	Step Volt Reg	3	840
158	Hanna - Laporte - Hanna Twp	Distribution	Unattended	69	12		11	1	1	Step Volt Reg	3	999
159	Hanover - Lake - Hanover Twp	Distribution	Unattended	69	12		56	2	0			
160	Hebron - Porter - Hebron	Distribution	Unattended	69	12		21	1	1	Step Volt Reg	6	2,118
161	Helmer - Steuben - Salem Twp	Distribution	Unattended	69	12		14	1	1	Step Volt Reg	6	1,680
162	Hillsdale - Jasper - Demotte	Distribution	Unattended	69	12		7	1	0	Step Volt Reg	3	750
163	Hobart - Lake - Hobart	Distribution	Unattended	69	12		50	2	0			
164	Honey Creek - White - Honey Creek Twp	Distribution	Unattended	69	12		10	2	0	Step Volt Reg	6	2,238
165	Hoosier Hill - Steuben - Angola	Distribution	Unattended	69	12		56	2	0			
166	Horn Ditch - Elkhart - Clinton Twp	Distribution	Unattended	69	12		56	2	0			
167	Howe - Lagrange - Lima Twp	Distribution	Unattended	69	12		28	2	0	Step Volt Reg	6	2,496
168	Hudson - Steuben - Ashley	Distribution	Unattended	69	12		14	1	0	Step Volt Reg	3	1,398
169	Idaville - White - Lincoln Twp	Distribution	Unattended	69	12		5	1	0	Step Volt Reg	3	343
170	Illinois - Elkhart - Goshen	Distribution	Unattended	69	12		56	2	0			
171	Independence Hill - Lake - Ross Twp	Distribution	Unattended	69	12		56	2	0			
172	Indian Creek - Elkhart - Jefferson Twp	Distribution	Unattended	69	12		56	2	0	Capacitors	1	5,400
173	Ironwood - Marshall - Center Twp	Distribution	Unattended	69	12		4	1	0	Step Volt Reg	3	501

174	James - Steuben - Pleasant Twp	Distribution	Unattended	69	12		21	2	0	Step Volt Reg	3	999
175	Kentland - Newton - Kentland	Distribution	Unattended	69	12		11	1	1	Step Volt Reg	2	746
176	Kingsbury - Laporte - Kingsbury	Distribution	Unattended	69	12		14	1	0	Step Volt Reg	3	1,248
177	Kingsford Heights - Laporte - Kingsford Heights	Distribution	Unattended	69	12		6	1	0	Step Volt Reg	3	840
178	Knox - Starke - Knox	Distribution	Unattended	69	12		29	3	0	Step Volt Reg	9	3,237
179	Knox Jct - Marshall - West Twp	Distribution	Unattended	69	12		7	1	0	Step Volt Reg	3	840
180	Lake Hills - Lake - St John Twp	Distribution	Unattended	69	12		28	1	1			
181	Laporte - Laporte - Laporte	Distribution	Unattended	69	12		56	2	0			
182	Lawton - Pulaski - Tippecanoe Twp	Distribution	Unattended	69	12		7	1	0	Step Volt Reg	3	840
183	Lincoln Square - Lake - North Twp	Distribution	Unattended	69	12		45	2	0			
184	Link - Pulaski - Indian Creek Twp	Distribution	Unattended	69	12		11	1	0	Step Volt Reg	3	999
185	Lowell - Lake - Lowell	Distribution	Unattended	69	12		56	2	0			
186	Malden - Porter - Morgan Twp	Distribution	Unattended	69	12		21	2	0	Step Volt Reg	6	1,998
187	Maplewood - Lake - Crown Point	Distribution	Unattended	69	12		22	1	0			
188	Marshall - Marshall - North Twp	Distribution	Unattended	69	34		8	1	0			
189	McCool - Porter - Porter	Distribution	Unattended	69	12		56	2	0			
190	Mckinley - Kosciusko - Warsaw	Distribution	Unattended	69	12		56	2	0			
191	Meadow Lane - Lake - Dyer	Distribution	Unattended	69	12		39	1	0			
192	Medaryville - Pulaski - Medaryville	Distribution	Unattended	69	12		6	1	1	Step Volt Reg	3	840
193	Mentone - Kosciusko - Mentone	Distribution	Unattended	69	12		14	2	0	Step Volt Reg	6	1,500
194	Merrillville - Lake - Ross Twp	Distribution	Unattended	69	12		45	2	0			
195	Middlebury - Elkhart - Middlebury	Distribution	Unattended	69	12		45	2	0			
196	Midway - Elkhart - Jefferson Twp	Distribution	Unattended	69	12		11	1	0	Step Volt Reg	3	1,119
197	Milford - Kosciusko - Milford	Distribution	Unattended	69	12		21	2	0	Step Volt Reg	6	2,118
198	Milroy - Jasper - Milroy Twp	Distribution	Unattended	69	12		7	1	0	Step Volt Reg	3	384
199	Mississippi - Lake - Hobart Twp_a	Distribution	Unattended	69	12		14	1	0			
200	Mississippi - Lake - Hobart Twp_b	Distribution	Unattended	34	12		22	1	0			
201	Mobile Sub #3 - Porter - Washingtong Twp	Distribution	Unattended	69	12		15	1	0			
202	Mobile Sub #4 - Porter - Washington Twp	Distribution	Unattended	69	12		20	1	0			
203	Mobile Sub #2 - Porter - Washington Twp	Distribution	Unattended	69	12		15	1	0			
204	Model - Elkhart - Goshen	Distribution	Unattended	69	12		56	2	0			
205	Monon - White - Monon	Distribution	Unattended	69	12		21	2	0	Step Volt Reg	6	2,118
206	Monoquet - Kosciusko - Plain Twp	Distribution	Unattended	69	12		21	1	0	Step Volt Reg	6	2,118
207	Moody - Jasper - Barkley Twp	Distribution	Unattended	69	12		3	1	0	Step Volt Reg	3	343
208	Morocco - -	Distribution	Unattended	69	12		21	2	0			
209	Nappanee - Elkhart - Nappanee	Distribution	Unattended	69	12		56	2	0	Step Volt Reg	9	3,237
210	Nevada Mills - Steuben - Jamestown	Distribution	Unattended	69	12		7	1	0	Step Volt Reg	3	750
211	New Paris - Elkhart - Jackson Twp	Distribution	Unattended	69	12		28	2	0	Step Volt Reg	6	2,496
212	Newbury - Lagrange - Newbury Twp	Distribution	Unattended	69	12		28	2	0	Step Volt Reg	5	2,080
213	North Judson - Starke - North Judson	Distribution	Unattended	69	12		22	3	0			
214	North Liberty - St Joseph - North Liberty	Distribution	Unattended	69	12		14	2	0	Step Volt Reg	6	1,749

215	North Webster - Kosciusko - North Webster	Distribution	Unattended	69	12		21	2	0	Step Volt Reg	6	2,238
216	Northridge - Elkhart - Middlebury	Distribution	Unattended	69	12		14	1	0	Step Volt Reg	3	1,248
217	Northwood - Elkhart - Locke Twp	Distribution	Unattended	69	12		28	1	0			
218	Novak Road - Lake - St John	Distribution	Unattended	69	12		28	1	0			
219	O'Leary - Lake - Merrillville	Distribution	Unattended	69	12		28	1				
220	Orchard Grove - Lake - Cedar Creek Twp	Distribution	Unattended	69	12		42	2	0			
221	Oswego - Kosciusko - Plain Twp	Distribution	Unattended	69	12		11	2	0	Step Volt Reg	3	1,119
222	Palmira - Lake - Hanover Twp	Distribution	Unattended	69	12		28	1	0			
223	Parr - Jasper - Union Twp	Distribution	Unattended	69	12		5	1	0	Capacitors	3	6,300
224	Pidco - Marshall - Plymouth	Distribution	Unattended	69	12		56	2				
225	Pierceton - Kosciusko - Pierston	Distribution	Unattended	69	12		20	1	1	Step Volt Reg	6	1,680
226	Pine Creek - Benton - Grant Twp	Distribution	Unattended	69	12		8	1	1	Step Volt Reg	3	999
227	Pine Manor - Elkhart - Elkhart Twp	Distribution	Unattended	69	12		56	2	0			
228	Pinola - Laporte - Scipio Twp	Distribution	Unattended	69	12		11	1	0	Step Volt Reg	3	1,119
229	Plum Creek - Lake - Dyer	Distribution	Unattended	69	12		28	1	0			
230	Rand - Lake - Hobart	Distribution	Unattended	69	12		31	2	0			
231	Remington - Jasper - Remington	Distribution	Unattended	69	12		14	1	1	Step Volt Reg	6	1,680
232	Rock Run - Elkhart - Goshen	Distribution	Unattended	69	12		56	2	0			
233	Rolling hills - Lake - Schererville	Distribution	Unattended	69	12		28	1	0			
234	Ross - Lake - Calumet Twp	Distribution	Unattended	69	12		14	1	0			
235	Rozella - Kosciusko - Warsaw	Distribution	Unattended	69	12		11	1	0	Step Volt Reg	3	999
236	Salem - Pulaski - Francesville	Distribution	Unattended	69	12		11	1	1	Step Volt Reg	3	1,119
237	Sand Creek - Porter - Liberty	Distribution	Unattended	69	12		28	1	0			
238	Schererville - Lake - Schererville	Distribution	Unattended	69	12		56	2	0			
239	Schneider - Lake - Schneider	Distribution	Unattended	69	12		21	2	0	Step Volt Reg	3	1,119
240	Shilo - Marshall - Polk Twp	Distribution	Unattended	69	12		6	1	0	Step Volt Reg	3	750
241	Silhavy - Washington - Porter	Distribution	Unattended	69	12		28	1	0			
242	Sixty-First Ave - Lake - Ross Twp	Distribution	Unattended	69	12		50	2	0			
243	Smith Ditch - Porter - Center Twp	Distribution	Unattended	69	12		28	1	0			
244	South Chalmers - White - Big Creek Twp	Distribution	Unattended	69	12		14	2	0	Step Volt Reg	6	1,500
245	South Haven - Porter - Portage Twp	Distribution	Unattended	69	12		50	2	0			
246	South Lake - Lake - Ross Twp	Distribution	Unattended	69	12		56	2	0			
247	South Milford - Lagrange - Milford Twp	Distribution	Unattended	69	12		11	1	1	Step Volt Reg	3	999
248	Spectacle Lake - Porter - Center Twp	Distribution	Unattended	69	12		45	2	0			
249	Spring - Lagrange - Lagrange	Distribution	Unattended	69	12		21	2	0	Step Volt Reg	6	2,238
250	Stone Lake - Elkhart - York Twp	Distribution	Unattended	69	12		0	0		Capacitors	3	12,000
251	Summer Tree - Lake - Center Twp	Distribution	Unattended	69	12		56	2	0			
252	Summit - Laporte - Center Twp	Distribution	Unattended	69	12		11	1	0	Step Volt Reg	3	999
253	Syracuse - Kosciusko - Syracuse	Distribution	Unattended	69	12		25	2	0	Step Volt Reg	6	2,038
254	Third St - Marshall - Bremen	Distribution	Unattended	69	12		14	2	0	Capacitors	2	10,800
255	Topeka - Lagrange - Topeka	Distribution	Unattended	69	12		13	1	0	Step Volt Reg	3	1,398
256	Township - Porter - Liberty Twp	Distribution	Unattended	69	12		28	1	0			
257	Twin Lakes - White - Monticello	Distribution	Unattended	69	12		28	1	0			
258	Veterans Hwy - Lake - Crown Point	Distribution	Unattended	69	12		28	1	0			
259	Wakarusa - Elkhart - Harrison	Distribution	Unattended	69	12		32	3	0	Step Volt Reg	9	3,357

260	Wanatah - Laporte - Wanatah	Distribution	Unattended	69	12		11	1	0	Step Volt Reg	3	1,119
261	Warner Rd - Elkhart - Syracuse	Distribution	Unattended	69	12		14	1	0	Step Volt Reg	3	1,398
262	Warsaw - Kosciusko - Warsaw	Distribution	Unattended	69	12		56	2	0			
263	Washington - Porter - Valparaiso	Distribution	Unattended	69	12		56	2	0			
264	Waterloo - Dekalb - Waterloo	Distribution	Unattended	69	12		21	2	1	Step Volt Reg	6	2,238
265	Wawasee - Koscuisko - Turkey Creek Twp	Distribution	Unattended	69	12		11	1	0	Step Volt Reg	3	1,119
266	Wayne - Kosciusko - Wayne Twp	Distribution	Unattended	69	12		50	2				
267	Weirick - Kosciusko - Harrison Twp	Distribution	Unattended	69	12		5	1	0	Step Volt Reg	3	840
268	West Point - White - West Point Tsp	Distribution	Unattended	69	12		7	1	0	Step Volt Reg		
269	Westville - Laporte - Portage Twp	Distribution	Unattended	69	12		21	2	0	Step Volt Reg	4	1,124
270	Wheeler - Porter - Washington Twp	Distribution	Unattended	69	12		52	2	0			
271	Williamsburg - Porter - Washington Twp	Distribution	Unattended	69	12		14	1	0			
272	Willowdale - Porter - Portage	Distribution	Unattended	69	12		28	1	0			
273	Winamac - Pulaski - Winamac	Distribution	Unattended	69	12		21	2	1	Capacitors	2	21,600
274	Winfield - Lake - Winfield	Distribution	Unattended	69	12		28	1				
275	Wolcottville - Lagrange - Wolcottville	Distribution	Unattended	69	12		21	2	0	Step Volt Reg	6	2,238
276	Woodland Park - Porter - Portage	Distribution	Unattended	69	12		22	1	0			
277	Wooster - Kosciusko - Wayne	Distribution	Unattended	69	12		11	1	0	Step volt Reg	3	999
278	Broadmoor - Lake - Munster	Distribution	Unattended	34	12		50	2	0			
279	Central Ave - Lake - Lake Station_a	Distribution	Unattended	34	12		14	1	0			
280	Central Ave - Lake - Lake Station_b	Distribution	Unattended	34	4		4	1	0			
281	Chase - Lake - Gary	Distribution	Unattended	34	4		8	1	0			
282	Clark Road - Lake - Gary	Distribution	Unattended	34	4		0	0	0			
283	Cleveland - Lake - Calumet Twp	Distribution	Unattended	34	4		0	0	0			
284	Cline - Lake - Highland	Distribution	Unattended	34	12		22	1	0			
285	Colfax - Lake - Calumet Twp	Distribution	Unattended	34	12		14	1	0			
286	Columbia Ave - Lake - Hammond	Distribution	Unattended	34	12		22	1	0			
287	Coolspring - Laporte - Coolspring Twp	Distribution	Unattended	34	12		21	2	0	Step Volt Reg	6	2,238
288	Crocker - Porter - Porter	Distribution	Unattended	34	12		28	2	0	Voltage Reg	5	2,080
289	Decatur - Lake - Gary_a	Distribution	Unattended	34	12		10	1	0			
290	Decatur - Lake - Gary_b	Distribution	Unattended	34	4		7	1	0			
291	Delaware - Lake - Gary	Distribution	Unattended	34	12		14	1	0			
292	Eighth St - Laporte - Michigan City	Distribution	Unattended	34	12		45	2	0			
293	Elliott - Lake - Munster	Distribution	Unattended	34	12		28	1	0			
294	Elm - Lake - East Chicago	Distribution	Unattended	34	4		10	2	2			
295	Elmwood - Lake - Hammond	Distribution	Unattended	34	12		14	1	0			
296	Fairbanks - Lake - Gary	Distribution	Unattended	34	4		0	0	0			
297	Fayette - Lake - Hammond	Distribution	Unattended	34	4		0	0	0			
298	Fisher - Lake - Munster	Distribution	Unattended	34	12		56	2	0			
299	Fortieth Ave - Lake - Gary	Distribution	Unattended	34	4		0	0	0			
300	Forty-Ninth Ave - Lake - Gary	Distribution	Unattended	34	4		0	0	0			
301	Freyer - Laporte - Michigan City	Distribution	Unattended	34	12		25	2	0	Step Volt Reg	6	2,238
302	Furnessville - Porter - Westchester Twp	Distribution	Unattended	34	12		21	2		Step Volt Reg	3	1,119
303	Gary Heights - Lake - Gary	Distribution	Unattended	34	4		0	0	0			
304	Gibson - Lake - Hammond	Distribution	Unattended	34	12		22	1	0			
305	Gleason - Lake - Gary_a	Distribution	Unattended	34	12		14	1	0			
306	Gleason - Lake - Gary_b	Distribution	Unattended	34	12		9	1	0			

307	Glen Park - Lake - Calumet Twp	Distribution	Unattended	34	12		14	1	0			
308	Griffith - Lake - Griffith	Distribution	Unattended	34	12		17	1	0			
309	Guthrie - Lake - East Chicago	Distribution	Unattended	34	12		28	2	0			
310	Hamilton - Lake - Gary	Distribution	Unattended	34	4		0	0	0			
311	Harrison - Lake - Hammond	Distribution	Unattended	34	12		28	2	0			
312	Hessville - Lake - Hammond	Distribution	Unattended	34	12		22	1	0			
313	Highland Shopping Center - Lake - Highland	Distribution	Unattended	34	12		0	0	0			
314	Hobart Road - Lake - Gary	Distribution	Unattended	34	4		0	0	0			
315	Hyde Park - Lake - Calumet Twp	Distribution	Unattended	34	12		14	1				
316	Idaho - Lake - Gary	Distribution	Unattended	34	12		14	1	0			
317	Indian Boundary - Lake - Gary	Distribution	Unattended	34	12		14	1	0			
318	Indiana Harbor - Lake - East Chicago	Distribution	Unattended	34	12		28	2	0			
319	Johnson - Lake - Gary	Distribution	Unattended	34	12		14	1	0			
320	Karwick Road - Laporte - Coolspring	Distribution	Unattended	34	12		11	1	0	Step Volt Reg	3	999
321	Kentucky - Laporte - Michigan City	Distribution	Unattended	34	12		45	2	0			
322	Keffer - Laporte - Michigan City	Distribution	Unattended	34	12		28	1	0			
323	Lakeland - Laporte - Michigan City	Distribution	Unattended	34	12		11	1	0	Step Volt Reg	3	1,119
324	Liable - Lake - Highland	Distribution	Unattended	34	12		14	1	0			
325	Linbergh - Lake - Hammond	Distribution	Unattended	34	12		28	2	0			
326	Louisana - Lake - Gary	Distribution	Unattended	34	4				0			
327	Madison - Lake - Gary	Distribution	Unattended	34	12		45	2	0			
328	Mason Ave - Lake - Gary	Distribution	Unattended	34	12		11	1	0	Step Volt Reg	3	833
329	Maynard - Lake - Munster	Distribution	Unattended	34	12		50	2	0			
330	Merlin St - Lake - Hammond	Distribution	Unattended	34	12		5	1	0	Step Volt Reg	3	750
331	Montgomery - Lake - Gary	Distribution	Unattended	34	12		14	1	0			
332	Nealon Dr - Porter - Portage	Distribution	Unattended	34	12		28	1	0			
333	New Chicago - Lake - Hobart Twp	Distribution	Unattended	34	4		0	0	0			
334	North Hammond - Lake - Hammond	Distribution	Unattended	34	12		14	1	0			
335	Ohio - Laporte - Michigan City	Distribution	Unattended	34	12		45	2	0	Step Volt Reg	6	4,002
336	One twentieth St - -	Distribution	Unattended	34	12		14	1	0			
337	Port of Indiana - Porter - Burns Harbor	Distribution	Unattended	34	12		21	2	0	Step Volt Reg	6	1,998
338	Prairie Park - Lake - East Chicago	Distribution	Unattended	34	12		14	1	0			
339	Pullman-Standard - Lake - Hammond	Distribution	Unattended	34	12		28	1	0			
340	Ridge Road - Lake - Griffith	Distribution	Unattended	34	12		22	1	0			
341	Robertsdale - Lake - Hammond	Distribution	Unattended	34	12		14	1	0			
342	Sibley - Lake - Hammond	Distribution	Unattended									
343	South Hammond - Lake - Hammond	Distribution	Unattended	34	12		56	2	0			
344	Springwood - Laporte - Michigan City	Distribution	Unattended	34	12		14	1	0			
345	Tilden - Laporte - Michigan City	Distribution	Unattended	34	12		28	2	0			
346	TOD - Lake - East Chicago	Distribution	Unattended	34	12		28	1	0			
347	Tompkins - Lake - Gary_a	Distribution	Unattended	34	12		28	1	0			
348	Tompkins - Lake - Gary_b	Distribution	Unattended	34	4		8	1	0			
349	Torrence - Lake - Hammond	Distribution	Unattended	34	12		14	1	0			
350	University - Lake - Gary	Distribution	Unattended	34	12		10	1	0			
351	Viginia - Lake - Gary	Distribution	Unattended	34	12		36	2	0			
352	Waite - Lake - Gary	Distribution	Unattended	34	12		14	1	0			
353	Whiting - Lake - Whiting	Distribution	Unattended	34	12		14	1	0			
354	Wickliffe - Porter - Ogeden Dunes	Distribution	Unattended	34	12		21	2	0	Step Volt Reg	6	2,238
355	Willow Court - Lake - Hammond	Distribution	Unattended	34	12		28	1	0			
356	Wilson - Lake - Gary	Distribution	Unattended	34	12		14	1	0			

357	Woodmar - Lake - Hammond	Distribution	Unattended	34	12		28	1	0			
358	Star Miling - Lagrange - Lima Twp	Distribution	Unattended	12	2		0	3	0			
360	TotalDistributionSubstationMember							345	19		414	266,904
361	TotalGenerationSubstationMember							0	0		0	0
362	TotalTransmissionSubstationMember							158	4		108	962,568

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/20/2026	Year/Period of Report 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 Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Contsruction work in progress (3)	NiSource Corporate Services Company	107	198,533,943
3	Adminstrative and general salaries (2)	NiSource Corporate Services Company	920	97,864,396
4	[(a)] Outside services employed (1)	NiSource Corporate Services Company	923	79,835,188
5	Maintenance of general plant	NiSource Corporate Services Company	932	23,005,248
6	Office supplies and expenses	NiSource Corporate Services Company	921	5,222,204
7	Rent expenses	NiSource Corporate Services Company	931	5,134,480
8	Operation Supervision for Engineering over Gas Distribution	NiSource Corporate Services Company	870	4,327,766
9	Customer records and collection expenses	NiSource Corporate Services Company	903	2,597,864
10	Other regulatory assets	NiSource Corporate Services Company	182.3	1,733,915
11	Miscellaneous customer service and informational expenses	NiSource Corporate Services Company	910	516,048
12	Mains and Services expense	NiSource Corporate Services Company	874	500,236
13	Miscellaneous general expenses	NiSource Corporate Services Company	930.2	489,960
14	Preliminary survey and investigation charges	NiSource Corporate Services Company	183	361,196
15	Injuries and damages	NiSource Corporate Services Company	925	204,681
16	Operation Purchase Gas Measuring Stations	NiSource Corporate Services Company	807	144,322
17	Maintenance of Mains	NiSource Corporate Services Company	887	142,125
18	Operation supervision and engineering - Distribution	NiSource Corporate Services Company	580	139,693
19	Other Operations expenses	NiSource Corporate Services Company	880	136,234
20	Meter and House Regulator expense	NiSource Corporate Services Company	878	135,586
21	Operations Installation Service Expense	NiSource Corporate Services Company	879	135,586
22	General advertising expenses	NiSource Corporate Services Company	930.1	76,345
23	Amortization	NiSource Corporate Services Company	405	68,530
24	Generation Maintenance Measuring Regulatory Station Expense	NiSource Corporate Services Company	889	55,063
25	State and Local Tax Penalties	NiSource Corporate Services Company	426	52,848
26	Generation Measuring Regulatory Station Expense	NiSource Corporate Services Company	875	49,359
27	Industrial Maintenance Measuring Regulatory Station Expense	NiSource Corporate Services Company	890	43,396
28	Industrial Measuring Regulatory Station Expense	NiSource Corporate Services Company	876	43,375
29	Regulatory commission expenses	NiSource Corporate Services Company	928	31,054
30	Property insurance	NiSource Corporate Services Company	924	28,955
31	Maintenance of Product Equipment	NiSource Corporate Services Company	742	2,529
32	Electric Labor and Materials	NiSource Corporate Services Company	505	548
33	Generation expenses	NiSource Corporate Services Company	548	509
34	Demonstrating and selling expenses	NiSource Corporate Services Company	912	369
35	Other Maint Equipment	NiSource Corporate Services Company	894	5
36	Operation supervision and engineering - Power Production	NiSource Corporate Services Company	500	(2,430)
37	Property taxes	NiSource Corporate Services Company	408	(108,706)
38	Interest expense	NiSource	430	129,940,235
39	Employee pensions and benefits	NiSource	926	1,302,973
40	Interest income	NiSource	419	
41	Injuries and damages	NiSource Insurance Corporation	925	4,018,594
42	Prepaid property insurance	NiSource Insurance Corporation	165	3,993,778
43	Employee pensions and benefits	NiSource Insurance Corporation	926	2,576,742
44	Property insurance	NiSource Insurance Corporation	924	536,444

45	Rent expense	NiSource Development Company	931	4,588,096
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Financing services	NIPSCO Accounts Receivable Corp.	426	(12,158,616)
22	Interest income	NIPSCO Accounts Receivable Corp.	419	(3,251,325)
42				

FOOTNOTE DATA

(a) Concept: DescriptionOfNonPowerGoodOrService

(1) Amounts recorded by NiSource Corporate Services Company related to depreciation and amortization, taxes, miscellaneous income/losses, affiliated interest on debt, allowance for borrowed AFUDC, distribution and maintenance are reflected in account 923, outside services employed above.

(2) Amounts recorded by NiSource Corporate Services Company related to employee pension and benefits are reflected in account 920, administrative and general salaries above.

(3) Amounts recorded by NiSource Corporate Services Company related to plant materials and operating supplies are reflected in account 107, construction work in progress above.