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)	Year/Period of Report
Northern Indiana Public Service Company LLC	End of: 2022/ Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

III. What and Where to Submit

a. Submit FERC 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.
b. The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.
c. Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426
d. For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

   The CPA Certification Statement should:

   a. Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and
   b. Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

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

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

   "In connection with our regular examination of the financial statements of [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.
f. 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.
g. Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

IV. When to Submit

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

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

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

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

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

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

X. 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

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

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

EXCERPTS FROM THE LAW

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

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

3. 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;
4. 'Person' means an individual or a corporation;
5. 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;
7. 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......
11. "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

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

a. FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and
b. FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

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

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

"Sec. 304.

a. Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may 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 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: 2022/ 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 Christopher Cubenas	06 Title of Contact Person Controller
07 Address of Contact Person (Street, City, State, Zip Code) 801 E. 86th Avenue, Merrillville, IN 46410	

08 Telephone of Contact Person, Including Area Code 219-647-5531	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/17/2023

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 02 Title VP, Chief Accounting Officer & Controller	03 Signature /s/ Gunnar J. Gode	04 Date Signed (Mo, Da, Yr) 04/17/2023

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: 04/17/2023	Year/Period of Report End of: 2022/ 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".

36	**Accumulated Deferred Investment Tax Credits**	266	
37	**Other Deferred Credits**	269	
38	**Accumulated Deferred Income Taxes-Accelerated Amortization Property**	272	none
39	**Accumulated Deferred Income Taxes-Other Property**	274	
40	**Accumulated Deferred Income Taxes-Other**	276	
41	**Other Regulatory Liabilities**	278	
42	**Electric Operating Revenues**	300	
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	
64	**Hydroelectric Generating Plant Statistics**	406	none
65	**Pumped Storage Generating Plant Statistics**	408	none
66	**Generating Plant Statistics Pages**	410	
0	**Energy Storage Operations (Large Plants)**	414	none
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: 04/17/2023	Year/Period of Report End of: 2022/ 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: 04/17/2023	Year/Period of Report End of: 2022/ 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 NiSource Inc.

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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	(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.			
6	(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.			
7	(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.			

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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	President, Chief Operating Officer & Chief Executive Officer	Michael W. Hooper	400,000		
2	EVP & Chief Financial Officer	Donald E. Brown	266,705		
3	SVP, Projects	James E. Zucal	163,749	2022-07-01	
4	previously SVP, Transformation and Major Projects	James E. Zucal - a			2022-06-30
5	SVP, Electric Operations	Ronald E. Talbot	369,052		
6	SVP, Strategy and Chief Risk Officer	Shawn Anderson	202,360		
7	SVP and Corporate Secretary	Kimberly S. Cuccia	169,240	2022-04-05	
8	previously VP and Interim Corporate Secretary	Kimberly S. Cuccia - a			2022-04-04
9	VP, Chief Accounting Officer & Controller	Gunnar J. Gode	131,435		
10	VP and Chief Tax and Procurement Officer	Sandra E. Brummitt	130,103		2022-06-30
11	VP, Regulatory & Major Accounts	Erin E. Whitehead	185,658		
12	VP, Gas Operations	Steven W. Sylvester	144,980		
13	VP & Treasurer	Randy G. Hulen	123,207		

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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: 04/17/2023	Year/Period of Report End of: 2022/ 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	Attachment O:	
27	Midwest ISO FERC Electric Tariff Original Volume No. 1	ER98-1438-000
28	Midwest ISO FERC Electric Tariff First Revised Volume No. 1	ER98-1438-007
29	Midwest ISO FERC Electric Tariff Second Revised Volume No. 1	ER04-458-004
30	Midwest ISO FERC Electric Tariff Second Revised Volume No. 1	ER04-895-000
31	Midwest ISO FERC Electric Tariff Second Revised Volume No. 1	ER05-122-000
32	Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER05-1085-001; ER04-458-008

33	Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER04-691-014; EL04-104-013; EL04-104-032
34	Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER04-691-034; EL04-104-013; EL04-104-032
35	Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER06-159-000
36	Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER07-113-000
37	Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER07-113-002
38	Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	OA08-4-001
39	Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER09-15-001
40	Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER09-91-000; ER09-573-000
41	Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER09-1779-000
42	Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER10-1492-000
43	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER11-2700-000
44	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER11-2700-004
45	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER11-3251-000
46	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER11-3704-000
47	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-297-000
48	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-310-000
49	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-578-000
50	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-1667-000
51	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER13-307-000
52	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER13-674-002
53	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-1547-000
54	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-1827-000
55	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-2379-000
56	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-102-000
57	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-421-000 and ER14-421-001
58	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-260-000
59	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-649-000
60	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-2379-003
61	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-142-000
62	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-277-000
63	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-358-000
64	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-2379-004
65	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1067-000
66	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1210-000
67	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1490-000
68	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1067-001
69	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-314-000
70	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1210-001
71	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-2364-000
72	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-18-000
73	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-1322-000
74	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-1333-000

75	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-215-001
76	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-893-000
77	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-2323-000
78	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-2323-001
79	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-94-000
80	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-788-000
81	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-1159-000
82	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-1982-000
83	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-249-000
84	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-652-000
85	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-2050-000
86	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-2050-002
87	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER20-1167-000
88	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-200-000
89	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-262-000
90	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-1510-000
91	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-1516-000
92	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER22-1602-000
93	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-2050-000
94	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-2133-000
95	Attachment MM:	
96	Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER10-1791
97	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-312-000
98	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-450-000
99	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-480-002
100	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-480-003
101	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-715-000
102	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER12-715-002
103	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER13-263-001
104	Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1 (Midwest Independent Transmission System - FERC Electric Tariff)	ER13-1169-000
105	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-1169-001
106	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-2468-000
107	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER12-480-006
108	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER12-480-007
109	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1689-000
110	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-392-000
111	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-2417-000
112	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-465-000
113	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER22-1579-000

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ Q4

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

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

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

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20230315321	03/01/2023	ER23-1213-000	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: 04/17/2023	Year/Period of Report End of: 2022/ 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: 04/17/2023	Year/Period of Report End of: 2022/ 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. NIPSCO entered into a joint venture agreement with U.S. Bancorp Community Development Corporation (tax equity partner) and EDPR (developer) to form Indiana Crossroads Wind Generation, LLC. The formation was approved by the IURC in Order 45524 dated July 28, 2021. The order approved NIPSCO treating its investments int he Joint Venture as a Regulatory Asset. This regulatory treatment was applied within for FERC reporting.

3. None

4. None

5. None

6. Refer to page 123 - Notes to Financial Statements.

7. None

8. In April of 2022, NIPSCO and the United Steelworker's Union agreed on a new four-year contract that runs through March 2026, with expected effect of annual increases of 3% to 3.5%.

9. In April 2022, we were notified that the FERC Office of Enforcement (“OE”) is conducting an investigation of an industrial customer for allegedly manipulating the MISO Demand Response (“DR”) market. The customer, along with us, are both cooperating with the investigation. If the OE ultimately were to seek to require the customer to repay any portion of the DR revenue received from MISO, it is reasonably possible that the OE would also seek to require us to disgorge administrative fees and foregone margin charges that we collected pursuant to our own IURC-approved tariff. We currently estimate the maximum amount of our disgorgement exposure to be $9.7 million, and the investigation is still ongoing. We intend to seek indemnification under our agreements with the customer for any liability we incur related to this matter.

10. None

12. N/A

13. Refer to page 104 and 105.

14. N/A

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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	12,575,093,545	11,876,060,505
3	Construction Work in Progress (107)	200	765,644,494	545,209,733
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		13,340,738,039	12,421,270,238
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	5,319,479,667	5,142,603,941
6	Net Utility Plant (Enter Total of line 4 less 5)		8,021,258,372	7,278,666,297
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)		8,021,258,372	7,278,666,297
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)		396,983	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	49,956,675	48,867,904
23	Noncurrent Portion of Allowances	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)		66,029,605	13,829,797
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		116,180,992	62,892,413
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)			12,554,920
36	Special Deposits (132-134)		23,977,409	7,787,924
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		26,896,681	31,197,318
41	Other Accounts Receivable (143)		33,815,770	40,242,699

42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,126,786	937,975
43	Notes Receivable from Associated Companies (145)		129,207,130	58,890,734
44	Accounts Receivable from Assoc. Companies (146)		11,128,433	10,043,101
45	Fuel Stock (151)	227	61,903,572	28,039,767
46	Fuel Stock Expenses Undistributed (152)	227	6,908,319	4,150,620
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	123,913,082	110,010,126
49	Merchandise (155)	227	8,694	9,828
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228		
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227	7,159,394	8,958,259
55	Gas Stored Underground - Current (164.1)		155,347,777	107,163,045
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		21,970,920	15,919,914
57	Prepayments (165)		42,032,730	41,547,092
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)		517,910	319,707
61	Accrued Utility Revenues (173)			
62	Miscellaneous Current and Accrued Assets (174)		19,861,420	5,957,584
63	Derivative Instrument Assets (175)		84,836,863	24,405,973
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		66,029,605	13,829,797
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)		682,329,713	492,430,839
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	1,569,492,946	1,253,474,128
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,033,501	3,240,428
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		2,721,681	4,362,471
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)		1,586,951	1,769,715
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	115,300,084	197,906,176
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	340,590,724	342,326,343
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		2,031,725,887	1,803,079,261
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		10,856,444,386	9,642,018,232

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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	206,741,159	206,741,159
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	2,756,236,536	2,430,092,728
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	41,363,624	40,274,853
13	(Less) Reaquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(102,157)	(75,172)
16	Total Proprietary Capital (lines 2 through 15)		3,863,257,457	3,536,051,863
17	**LONG-TERM DEBT**			
18	Bonds (221)	256		
19	(Less) Reaquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256	2,866,000,000	2,431,000,000
21	Other Long-Term Debt (224)	256	58,000,000	68,000,000
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		64,240	80,706
24	Total Long-Term Debt (lines 18 through 23)		2,923,935,760	2,498,919,294
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		23,682,544	21,874,461
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		266,278	276,145
29	Accumulated Provision for Pensions and Benefits (228.3)		231,539,302	282,387,531
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities		1,933,208	7,369,508
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		363,045,513	370,818,057
35	Total Other Noncurrent Liabilities (lines 26 through 34)		620,466,845	682,725,702
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)			
38	Accounts Payable (232)		398,046,166	310,025,220
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)		600,204,345	299,512,162

41	Customer Deposits (235)		66,479,683	64,811,362
42	Taxes Accrued (236)	262	127,312,929	83,831,546
43	Interest Accrued (237)		49,457,243	23,949,007
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		15,431,882	13,726,310
48	Miscellaneous Current and Accrued Liabilities (242)		176,781,310	180,629,104
49	Obligations Under Capital Leases-Current (243)		3,516,853	3,988,915
50	Derivative Instrument Liabilities (244)		3,021,761	7,814,160
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		1,933,208	7,369,508
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)		1,438,318,964	980,918,278
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		40,987,897	12,910,847
57	Accumulated Deferred Investment Tax Credits (255)	266	877,732	1,226,420
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	107,266,404	107,428,065
60	Other Regulatory Liabilities (254)	278	603,758,465	566,458,323
61	Unamortized Gain on Reaquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		1,127,162,545	1,132,556,284
64	Accum. Deferred Income Taxes-Other (283)		130,412,317	122,823,156
65	Total Deferred Credits (lines 56 through 64)		2,010,465,360	1,943,403,095
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		10,856,444,386	9,642,018,232

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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

6. Do not report fourth quarter data in columns (e) and (f)
7. 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.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

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 Utity 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	2,887,394,530	2,535,473,509			1,831,876,933	1,700,765,680	1,055,517,597	834,707,829		
3	Operating Expenses											
4	Operation Expenses (401)	320	1,676,753,143	1,331,301,725			925,356,420	762,434,926	751,396,723	568,866,799		
5	Maintenance Expenses (402)	320	200,325,719	192,417,238			146,144,204	147,567,487	54,181,515	44,849,751		
6	Depreciation Expense (403)	336	327,933,397	372,469,944			252,822,535	300,041,895	75,110,862	72,428,049		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336										
8	Amort. & Depl. of Utility Plant (404-405)	336	32,767,455	25,609,988			22,528,227	18,924,328	10,239,228	6,685,660		
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)		53,918,434	9,125,338			53,918,434	9,125,338				
13	(Less) Regulatory Credits (407.4)											

14	Taxes Other Than Income Taxes (408.1)	262	69,441,133	90,454,229			41,666,125	56,893,980	27,775,008	33,560,249		
15	Income Taxes - Federal (409.1)	262	80,642,777	29,936,681			79,204,768	24,185,890	1,438,009	5,750,791		
16	Income Taxes - Other (409.1)	262	16,140,241	212,457			10,420,434	(1,493,409)	5,719,807	1,705,866		
17	Provision for Deferred Income Taxes (410.1)	234, 272	94,764,117	145,446,892			28,304,129	94,581,875	66,459,988	50,865,017		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	124,274,301	98,767,146			68,533,878	61,674,107	55,740,423	37,093,039		
19	Investment Tax Credit Adj. - Net (411.4)	266	(348,688)	(368,712)			(32,680)	(4,188)	(316,008)	(364,524)		
20	(Less) Gains from Disp. of Utility Plant (411.6)											
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)											
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)											
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,428,063,427	2,097,838,634			1,491,798,718	1,350,584,015	936,264,709	747,254,619		
27	Net Util Oper Inc (Enter Tot line 2 less 25)		459,331,103	437,634,875			340,078,215	350,181,665	119,252,888	87,453,210		
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)			45,474								
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	1,088,771	2,327,872								

37	Interest and Dividend Income (419)		1,045,357	26,446									
38	Allowance for Other Funds Used During Construction (419.1)		13,005,191	10,277,032									
39	Miscellaneous Nonoperating Income (421)		10,285,603	(905,640)									
40	Gain on Disposition of Property (421.1)			785,099									
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		25,424,922	12,465,335									
42	Other Income Deductions												
43	Loss on Disposition of Property (421.2)			414,703									
44	Miscellaneous Amortization (425)		2,540,513	2,540,514									
45	Donations (426.1)		854,879	789,429									
46	Life Insurance (426.2)												
47	Penalties (426.3)		405,240	223,807									
48	Exp. for Certain Civic, Political & Related Activities (426.4)		18,463	112,239									
49	Other Deductions (426.5)		6,740,094	3,887,873									
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		10,559,189	7,968,565									
51	Taxes Applic. to Other Income and Deductions												
52	Taxes Other Than Income Taxes (408.2)	262											
53	Income Taxes-Federal (409.2)	262	(1,301,511)	(1,122,757)									
54	Income Taxes-Other (409.2)	262	(360,008)	(249,810)									
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	2,181,281	517,698									
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	2,076,606	3,009,534									
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)		(1,556,844)	(3,864,403)									

60	Net Other Income and Deductions (Total of lines 41, 50, 59)		16,422,577	8,361,173								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		4,924,978	5,173,700								
63	Amort. of Debt Disc. and Expense (428)		16,466	17,508								
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)		121,561,727	107,311,849								
68	Other Interest Expense (431)		27,016,459	10,538,493								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		4,998,529	2,749,638								
70	Net Interest Charges (Total of lines 62 thru 69)		148,521,101	120,291,912								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		327,232,579	325,704,136								
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)		327,232,579	325,704,136								

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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		2,430,092,728	2,106,716,465
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)		326,143,808	323,376,263
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			
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,756,236,536	2,430,092,728
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)		2,756,236,536	2,430,092,728
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		40,274,853	37,946,981
50	Equity in Earnings for Year (Credit) (Account 418.1)		1,088,771	2,327,872
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)		41,363,624	40,274,853

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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)	327,232,579	325,704,136
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	327,933,397	372,469,944
5	Amortization of (Specify) (footnote details)		
5.1	[(a)] Amortization of Electric Utility Plant	76,446,661	28,049,666
5.2	Amortization and Depletion of Gas Utility Plant	10,239,228	6,685,660
8	Deferred Income Taxes (Net)	(29,405,509)	44,187,910
9	Investment Tax Credit Adjustment (Net)	(348,688)	(368,712)
10	Net (Increase) Decrease in Receivables	(60,683,554)	3,433,770
11	Net (Increase) Decrease in Inventory	(108,704,677)	(39,791,247)
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	146,540,578	73,809,766
14	Net (Increase) Decrease in Other Regulatory Assets	(363,943,683)	70,816,552
15	Net Increase (Decrease) in Other Regulatory Liabilities	37,300,142	(17,386,318)
16	(Less) Allowance for Other Funds Used During Construction	13,005,191	10,277,032
17	(Less) Undistributed Earnings from Subsidiary Companies	1,088,771	2,327,872
18	Other (provide details in footnote):		
18.1	[(b)] Other (provide details in footnote):	(19,410,312)	(145,443,819)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	329,102,200	709,562,404
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(1,075,445,018)	(890,676,584)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant	(38,597,773)	(37,453,935)
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	(13,005,191)	(10,277,032)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(1,101,037,600)	(917,853,487)
36	Acquisition of Other Noncurrent Assets (d)		
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 Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	23,274,994	67,475,773
53	Other (provide details in footnote):		
53.1	Other - Customer Advances for Construction	28,077,050	(2,959,710)
53.2	Other - Restricted Cash	(16,189,485)	383,228
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(1,065,875,041)	(852,954,196)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	435,000,000	175,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)	299,201,455	
67	Other (provide details in footnote):		
70	Cash Provided by Outside Sources (Total 61 thru 69)	734,201,455	175,000,000
72	Payments for Retirement of:		
73	Long-term Debt (b)	(10,000,000)	
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other - Unamortized Discount on Long-Term Debt	16,466	17,508
76.2	Bond Issuance Costs		
78	Net Decrease in Short-Term Debt (c)		(19,070,796)
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	724,217,921	155,946,712
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)	(12,554,920)	12,554,920
88	Cash and Cash Equivalents at Beginning of Period	12,554,920	
90	Cash and Cash Equivalents at End of Period		12,554,920

FOOTNOTE DATA

(a) Concept: NoncashAdjustmentsToCashFlowsFromOperatingActivitiesDescription

Includes accounts 404 & 407.3.

(b) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivitiesDescription

2022

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

	2022
Asset Retirement Obligations	(7,772,544)
Deferred Income Taxes	33,685,238
Pensions and Benefits	(50,848,229)
Derivative Instrument Assets/Liabilities	(65,867,190)
Prepayments	(485,638)
Miscellaneous	71,878,051
Other - CF Page 120 Line 20	**(19,410,312)**

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

	2022
Income Taxes	30,193,762
Interest, net of amounts capitalized	121,033,672

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

	2022
Cash - BS Page 110 Line 35	—
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	**—**

2021

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

	2021
Asset Retirement Obligations	(37,936,260)
Deferred Income Taxes	32,745,651
Pensions and Benefits	(20,415,423)
Derivative Instrument Assets/Liabilities	(48,920,199)
Prepayments	(7,566,119)
Miscellaneous	(63,351,469)
Other - CF Page 120 Line 20	**(145,443,819)**

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

	2021
Income Taxes	(12,014,697)
Interest, net of amounts capitalized	114,937,293

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

	2021
Cash - BS Page 110 Line 35	12,554,920
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	**12,554,920**

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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 Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

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:

- 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.
- 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.
- 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.
- GAAP requires the regulatory assets and liabilities resulting from the implementation of ASC 740-10 (formerly SFAS No. 109) be presented as a net amount on the Balance Sheet. For FERC reporting purposes, these assets and liabilities are presented separately and are included in the Other Regulatory Assets within Deferred Debits and Regulatory Liabilities within Deferred Credits, respectively.
- 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.
- 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.
- GAAP requires any deferred costs associated with a debt issuance be presented as a reduction to debt on the Consolidated Balance Sheets. FERC requires any Unamortized Debt Expense to be separately states as a Deferred Debit on the Balance Sheet.
- GAAP requires the current portion of deferred income taxes be reported as a current asset or liability on the balance sheet. For FERC reporting purposes, the current portion of deferred income taxes is included in Accumulated Deferred Income Taxes, which is non-current.
- 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.
- GAAP requires the deferral as a regulatory asset or liability of certain amounts representing timing differences between profit and loss earned from the renewable energy investments under the application of HLBV accounting and the amount included in the regulated rates to recover our approved investments. For FERC reporting, HLBV accounting is not utilized and, therefore, amounts are not deferred.
- Our management has performed an evaluation of subsequent events through April 17, 2023, which is the date that our regulatory basis financial statements were available to be issued.

The Notes to Financial Statements below are as published for the year ended December 31, 2022, and are reported in accordance with GAAP. The Notes include Northern Indiana Public Service Company LLC, NIPSCO Accounts Receivable Corporation, Rosewater Wind Generation LLC, Indiana Crossroads Wind Generation LLC and Indiana Crossroads 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 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.

Defined Terms

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

Subsidiaries and Affiliates

NARC NIPSCO Accounts Receivable Corporation
NIPSCO ("we," "us" or "our") Northern Indiana Public Service Company LLC
NiSource NiSource Inc.
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
Rosewater Rosewater Wind Generation LLC and its wholly owned subsidiary, Rosewater Wind Farm LLC

Abbreviations

AFUDC Allowance for funds used during construction
ASC Accounting Standards Codification
ASU Accounting Standards Update
BTA Build-transfer agreement
CAP Compliance Assurance Process
CCRs Coal Combustion Residuals
COVID-19 ("the COVID-19 pandemic" or "the pandemic") Novel Coronavirus 2019
EPA United States Environmental Protection Agency
FAC Fuel adjustment clause
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
IRS Internal Revenue Service
IURC Indiana Utility Regulatory Commission
JV Joint Venture
LIBOR London InterBank Offered Rate
MGP Manufactured Gas Plant
MISO Midcontinent Independent System Operator
MW Megawatts
MWh Megawatt hours
NYMEX New York Mercantile Exchange
OPEB Other Postretirement and Postemployment Benefits
PCB Polychlorinated biphenyls
PPA Purchase power agreement
ROU Right of Use
TCJA Tax Cuts and Jobs Act of 2017
TDSIC Transmission, Distribution and Storage System Improvement Charge
VIE Variable Interest Entity

1. Nature of Operations and Summary of Significant Accounting Policies

A. Company Structure and Basis of Accounting Presentation. NIPSCO, a single member limited liability company with NiSource as its sole member, 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, serving an area of about 12,000 square miles.

NiSource, a Delaware corporation, is an energy holding company whose subsidiaries are fully regulated natural gas and electric utility companies serving approximately 3.7 million customers in six states.

Our primary business segments are: Gas Distribution Operations and Electric Operations. Our natural gas distribution operations serve approximately 859,000 customers in the northern part of Indiana. Our electric operations generate, transmit and distribute electricity to approximately 486,000 customers in 20 counties in the northern part of Indiana and engage in wholesale and transmission transactions. The consolidated financial statements include the accounts of NIPSCO, its subsidiary, NARC, and its variable interest entities, Rosewater, Indiana Crossroads Wind and Indiana Crossroads Solar joint ventures, after the elimination of all intercompany items.

Our accompanying Consolidated Financial Statements reflect all normal recurring adjustments that are necessary, in the opinion of management, to present fairly the results of our operations in accordance with GAAP in the United States of America.

Our management has performed an evaluation of subsequent events through March 23, 2022, 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 disclosures 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 the 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. 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.

recovered. Refer to Note 3, "Revenue Recognition," for additional information on customer-related accounts receivable.

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 charged and collected. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred on the Consolidated Balance Sheets and 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 8, "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.

Non-utility property includes renewable generation assets owned by JVs of which we are the primary beneficiary and is generally depreciated on a straight-line basis over the life of the associated asset. Refer to Note 5, "Property, Plant and Equipment," for additional information related to depreciation expense.

We capitalized AFUDC on all classes of property except organization costs, land, autos, office equipment, tools and other general property purchases. The allowance 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 pre-tax rate for AFUDC was 6.2% in 2022, 5.8% in 2021 and 5.5% in 2020.

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, 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 the 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.

External and internal costs associated with on-premise 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. Once the installed software is ready for its intended use, such deferred costs are amortized on a straight-line basis to "Operation and maintenance," generally over the minimum term of the contract plus contractually-provided renewal periods that are reasonable and 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 related to the acquisition of Northern Indiana Fuel and Light and Kokomo Gas. We test our goodwill for impairment annually as of May 1st or more frequently if events and circumstances indicate that goodwill might be impaired. Our fair value is determined using a combination of income and market approaches. Refer to Note 6, "Goodwill," for additional information.

H. Accounts Receivable Transfer Program. We have an agreement with a third party to sell certain accounts receivable without recourse. These transfers of accounts receivable are accounted for as secure borrowings. The entire gross receivables balance remains on the December 31, 2022 and 2021 Consolidated Balance Sheets and short-term debt is recorded in the amount of proceeds received from the purchasers involved in the transactions. Refer to Note 14, "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 revenue, and adjust future billings for such deferrals on a basis consistent with applicable IURC tariff provisions. These deferred balances are recorded as "Regulatory assets" or "Regulatory liabilities", as appropriate, on the Consolidated Balance Sheets. Refer to Note 8, "Regulatory Matters," for additional information.

J. Inventory. Our natural gas in storage, electric production fuel and materials and supplies are valued using the weighted average cost inventory methodology as approved by the IURC.
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 $171.2 million, $171.0 million and $148.0 million for 2022, 2021 and 2020, respectively. Additionally, capitalized costs, which are included in "Utility plant" on the Consolidated Balance Sheets, totaled $65.1 million and $59.4 million for 2022 and 2021, respectively. Additionally, regulatory-related costs, which are included in "Regulatory Assets" on the Consolidated Balance Sheets, totaled $0.9 million and zero for 2022 and 2021, respectively.

The amount of federal and state taxes payable to NiSource included in "Taxes accrued" on our Consolidated Balance Sheets was $36.2 million and $29.4 million as of December 31, 2022 and 2021, respectively. The amount of federal and state taxes receivable from NiSource included in "Income tax receivable" on our Consolidated Balance Sheets was zero and $6.3 million as of December 31, 2022 and 2021, respectively.

L. Accounting for Exchange and Balancing Arrangements of Natural Gas. Our Gas Distribution Operations segment enters 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 Gas Distribution Operations exchange agreement. Exchange gas is valued based on our regulatory jurisdiction requirements (for example, historical spot rate, spot at the beginning of the month). 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 the 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 9, "Risk Management Activities" for further information.

N. Income Taxes and Investment Tax Credits. We record income taxes to recognize full interperiod tax allocations. Under the asset and liability method, deferred income taxes are provided for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amount and the tax basis of existing assets and liabilities. Investment tax credits associated with regulated operations are deferred and amortized as a reduction to income tax expense over the estimated lives of the related properties.

To the extent certain of our deferred income taxes are recoverable or payable through future rates, regulatory assets and liabilities have been established. Regulatory assets for income taxes are primarily attributable to property-related tax timing differences for which deferred taxes had not been provided in the past, when regulators did not recognize such taxes as costs in the rate-making process. Regulatory liabilities for income taxes are primarily attributable to our obligation to refund to ratepayers deferred income taxes provided at rates higher than the current Federal income tax rate. Such property-related amounts are credited to ratepayers consistent with the IURC's direction.

Pursuant to the Internal Revenue Code and the Indiana Department of Revenue, we join in the filing of consolidated federal and state income tax returns with our parent company, NiSource. We are party to an agreement, the "Intercompany Income Tax Allocation Agreement," that provides for the allocation of consolidated tax liabilities. The Intercompany Tax Allocation Agreement generally provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax.

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 pension 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. We had one such interim remeasurement in the second quarter of 2022. See Note 11, "Pension and Other Postretirement 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 expenditures are actually made. The undiscounted 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 contaminations, 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 "Legal and environmental" for short-term portions of these liabilities and "Other noncurrent liabilities" for the respective long-term portion of these liabilities. Refer to Note 7, "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 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. Our actual exposure to liability is minimal due to coverage from NiSource's wholly-owned captive insurer who transfers risk to third party insurance providers for the majority of costs paid to claimants above our deductible.

S. VIEs and Allocation of Earnings. We fund a significant 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 JV' cash distributions and tax benefits to members is based on factors other than member's 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 adjusts the amount of the VIE's net income attributable to us and the noncontrolling tax equity member during that 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 Subsidiaries," we are subject to the accounting and reporting requirements of ASC 980. In accordance with these principles, we have recognized a regulatory liability or asset for amounts representing 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

We have evaluated recently issued accounting pronouncements and do not believe any pronouncements will have a significant impact on our Consolidated Financial Statements or Notes to Consolidated Financial Statements.
Recently Adopted Accounting Pronouncements

In March 2020, the FASB issued ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting* and in January 2021, the FASB issued ASU 2021-01, *Reference Rate Reform (Topic 848): Scope.* These pronouncements provide temporary optional expedients and exceptions for applying GAAP principles to contract modifications and hedging relationships to ease the financial reporting burdens of the expected market transition from LIBOR and other interbank offered rates to alternative reference rates. These pronouncements were effective upon issuance on March 12, 2020 through December 31, 2022. In December 2022, the FASB issued ASU 2022-06, *Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848*, to extend the temporary accounting rules under Topic 848 from December 31, 2022 to December 31, 2024, after which we will no longer be permitted to apply the relief in Topic 848. During the third quarter of 2022, we applied the practical expedient under Topic 848 which allowed for the continuation of cash flow hedge accounting for interest rate derivative contracts upon the transition from LIBOR to alternative reference rates. The third quarter of 2022, we applied the practical expedient under Topic 848 which allowed for the continuation of cash flow hedge accounting for interest rate derivative contracts upon the transition from LIBOR to alternative reference rates. The application of this expedient had no material impact on the Consolidated Financial Statements.

In November 2021, the FASB issued ASU 2021-10, *Government Assistance (Topic 832): Disclosures by Business Entities about Government Assistance*. This pronouncement requires certain annual disclosures for transactions with a government that are accounted for by applying a grant or contribution accounting model by analogy to other accounting guidance. This pronouncement is effective for financial statements issued for annual periods beginning after December 15, 2021. We adopted this pronouncement in the fourth quarter of 2022. The adoption of this pronouncement did not have an impact on the Notes to the Consolidated Financials Statements.

In September 2022, the FASB issued ASU 2022-04, *Liabilities-Supplier Finance Programs (Topic 405-50) - Disclosure of Supplier Finance Program Obligations*. This pronouncement requires that a buyer in a supplier finance program disclose sufficient information to allow a user of financial statements to understand the program's nature, activity during the period, changes from period to period, and potential magnitude. This pronouncement is expected to improve financial reporting by requiring new disclosures about supplier finance programs, thereby allowing financial statement users to better consider the effect of such programs on an entity's working capital, liquidity, and cash flows. This pronouncement is effective for fiscal years beginning after December 15, 2022. We adopted this pronouncement as of January 1, 2023. We had no active supplier finance programs as of December 31, 2022.

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, our Gas Distribution Operations segment 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 Gas Distributions Operations exchange agreement.

Revenue Disaggregation and Reconciliation. We disaggregate revenue from contracts with customers based upon reportable segment as well as by customer class.

The tables below reconcile revenue disaggregation by customer class to segment revenue, as well as to revenues reflected on the Statements of Consolidated Operations.

Year Ended December 31, 2022 *(in millions)*	Gas Distribution Operations	Electric Operations	Total
Customer Revenues			
Residential	$ 691.	$ 592.	$ 1,283.
Commercial	267.5	571	838.5
Industrial	85.1	560.6	645.7
Miscellaneous	10.7	12.5	23.2
Total Customer Revenues	$ 1,054.	$ 1,736.	$ 2,791.
Other Revenues	0.3	95.4	95.7
Total Operating Revenues	$ 1,055.	$ 1,831.	$ 2,887.

Year Ended December 31, 2021 *(in millions)*	Gas Distribution Operations	Electric Operations	Total
Customer Revenues			
Residential	$ 542.	$ 567.	$ 1,110.
Commercial	204.9	534.9	739.8
Industrial	76.8	493.4	570.2
Miscellaneous	8.4	9	17.4
Total Customer Revenues	$ 833.	$ 1,605.	$ 2,438.
Other Revenues	1.4	91.9	93.3
Total Operating Revenues	$ 834.	$ 1,697.	$ 2,531.

Year Ended December 31, 2020 *(in millions)*	Gas Distribution Operations	Electric Operations	Total
Customer Revenues			
Residential	$ 465.	$ 527.	$ 993.
Commercial	169.7	480.3	650
Industrial	67.2	412.1	479.3
Miscellaneous	7.6	20.9	28.5
Total Customer Revenues	$ 710.	$ 1,441.	$ 2,151.
Other Revenues	1	95.5	96.5
Total Operating Revenues	$ 711.	$ 1,536.	$ 2,248.

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 "Other revenues." When amounts previously recognized under alternative revenue accounting guidance are billed, we reduce the regulatory asset and record a customer account receivable.

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. Unbilled amounts of accounts receivable relate to a portion of a customer's consumption of gas or electricity from the date of the 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 heading 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, 2022 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, 2021	$ 168.	$ 137.
Balance as of December 31, 2022	193.8	186.5

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 collectibility. 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 collection experience, current information and reasonable and supportable forecasts. Internal and external inputs are used in our credit model including, but are not limited to, energy consumption trends, revenue projections, actual charge-off data, recoveries data, shut-offs customer delinquencies, final bill data, and inflation. 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.

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, 2022 and December 31, 2021 are presented in the tables below.

(in millions)	Gas Distribution Operations	Electric Operations	Total
Balance as of January 1, 2022	$ 5.	$ 3.	$ 9.
Current period provisions	4.8	6.9	11.7
Write-offs charged against allowance	(4.7)	(5.3)	(10.0)
Recoveries of amounts previously written off	0.3	0.5	0.8

Balance as of December 31, 2022	$ 6.	$ 5.	$ 12.

(in millions)	Gas Distribution Operations	Electric Operations	Total
Balance as of January 1, 2021	$ 8.	$ 9.	$ 18.
Current period provisions	2	1.4	3.4
Write-offs charged against allowance	(5.0)	(7.7)	(12.7)
Recoveries of amounts previously written off	0.4	0.4	0.8
Balance as of December 31, 2021	$ 5.	$ 3.	$ 9.

In connection with the COVID-19 pandemic, the IURC instituted a regulatory moratorium that impacted our ability to pursue our standard credit risk mitigation practices. Following the issuance of these moratoriums, we have been authorized to recognize a regulatory asset for bad debt costs above levels currently in rates. At the balance sheet date, in addition to our evaluation of the allowance for credit losses discussed above, we considered benefits available under governmental COVID-19 relief programs, the impact of unemployment benefits initiatives, and flexible payment plans being offered to customers affected by or experiencing hardship as a result of the pandemic, which could help to mitigate the potential for increasing customer account delinquencies. We also considered the on-time bill payment promotion and robust customer marketing strategy for energy assistance programs that we have implemented. Based upon this evaluation, we have concluded that the allowance for credit losses as of December 31, 2022 adequately reflected the collection risk and net realizable value of our receivables. See Note 8, "Regulatory Matters," for additional information on regulatory moratoriums and regulatory assets.

4. 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. VIEs and Allocation of Earnings," for information on our accounting policy for the VIEs.

We own and operating two wind facilities, Rosewater and Indiana Crossroads Wind, which have 102 MW and 302 MW of nameplate capacity, respectively. We also own one solar facility, Indiana Crossroads Solar, which is expected to go into service in 2023, and has 200 MW of nameplate capacity. 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 three entities.

Members of the respective JVs are NIPSCO (who is the managing member) and tax equity partners. Earnings, tax attributes and cash flows are allocated to both NIPSCO and the tax equity partners in varying percentages by category and over the life of the partnership. We and each tax equity partner contributed cash, and we also assumed an obligation to the developers of the wind facilities representing the remaining economic interest. The developers of the wind facilities are not a partner in the JV for federal income tax purposes and do not receive any share of earnings, tax attributes, or cash flows of each JV. Once the tax equity partner has earned their negotiated rate of return and we have reached the agreed upon contractual date, we have the option to purchase at fair market value from the tax equity partner the remaining interest in the respective JV. We have an obligation to purchase, through a PPA at established market rates, 100% of the electricity generated by the JVs.

The following table displays the total contributions paid and obligations incurred in the periods presented:

Year Ended December 31, *(in millions)*	**2022**	2021	2020
NIPSCO Cash Contributions	**$ 151.**	$ 2.	$ 0.
Tax Equity Partner Cash Contributions	**21.2**	245.1	86.1
NIPSCO's Obligation to Developers [(1)]	—	277.5	69.7
Total Contributions	**$ 173.**	$ 525.	$ 156.

[(1)] Outstanding amounts in "Obligations to renewable generation asset developer" in the Consolidated Balance Sheets.

We did not provide any financial or other support during the year that was not previously contractually required, nor do we expect to provide such support in the future.

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

at December 31, *(in millions)*	**2022**	2021
Net property, plant and equipment	**$ 978.**	$ 695.
Current assets	**25.7**	14.3
Total Assets [(1)]	**$ 1,004.**	$ 710.
Current liabilities	**$ 128.**	$ 10.
Asset retirement obligations	**30.6**	20.5
Total Liabilities	**$ 158.**	$ 30.

[(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.

5. Property, Plant and Equipment

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

At December 31, *(in millions)*		**2022**	2021
Property Plant and Equipment			
	Gas Distribution Utility [(1)]	**$ 3,980.**	$ 3,683.
	Electric Utility [(1)]	**7,162.4**	6,754.9
	Construction Work in Process	**1,065.5**	544.2
	Renewable Generation Assets [(2)]	**702.2**	702.4
	Non-Utility and Other	**1,397.3**	1,406.3
Total Property Plant and Equipment		**$ 14,308.**	$ 13,091.
Accumulated Depreciation and Amortization			
	Gas Distribution Utility [(1)]	**(1,274.2)**	$ (1,215.3
	Electric Utility [(1)]	**(2,557.4)**	(2,433.1)
	Renewable Generation Assets [(2)]	**(29.7)**	(6.5)
	Non-Utility and Other	**(1,259.4)**	(1,204.4)
Total Accumulated Depreciation and Amortization		**$ (5,120.7**	$ (4,859.3
Net Property, Plant and Equipment		**$ 9,187.**	$ 8,232.

[(1)] Our common utility plant and associated accumulated depreciation and amortization are allocated between Gas Distribution Utility and Electric Utility Property, Plant and Equipment.
[(2)] Our renewable generation assets are part of our electric segment and 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, "Variable Interest Entities," for additional information.

On October 1, 2021, we retired R.M. Schahfer Generating Station Units 14 and 15. The net book value of the retired units was reclassified from "Net Property, Plant and Equipment," to current and long-term "Regulatory Assets." The estimated net book value of R.M. Schahfer Generating Station's coal Units 14 and 15 and other associated plant retired was approximately $600 million. See Note 8, "Regulatory Matters" for additional details regarding the recovery of the regulatory assets associated with retired generating stations.

The weighted average depreciation provisions for utility plant, as a percentage of the original cost, for the periods ended December 31, 2022, 2021 and 2020 were as follows.

	2022	2021	2020
Electric Operations	**3.1%**	3.6%	3.4%
Gas Distribution Operations	**2.0%**	2.0%	2.1%

We recognized depreciation expense of $353.6 million, $376.1 million and $372.3 million for the years ended 2022, 2021 and 2020, respectively. The 2022 and 2021 depreciation expense amounts include an $11.0 million and $5.3 million increase related to the regulatory deferral of income (loss) associated with our JVs, which is not included in current rates. See Note 8, "Regulatory Matters," for additional information.

Amortization of on-premise Software Costs. We amortized $27.7 million, $22.1 million and $22.1 million in 2022, 2021 and 2020, respectively, related to software recorded as intangible assets. Our unamortized software balance was $86.5 million and $88.6 million at December 31, 2022 and 2021, respectively.

Amortization of Cloud Computing Costs. We amortized $4.8 million, $3.2 million and $1.6 million in 2022, 2021 and 2020, respectively, related to cloud computing costs to "Operation and maintenance" expense. Our unamortized cloud computing balance was $14.4 million and $17.5 million at December 31, 2022 and 2021, respectively.

6. Goodwill

Our goodwill assets as of December 31, 2022 and 2021 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, 2022, we completed a qualitative "step 0" assessment and determined that it was more likely than not that our estimated fair value substantially exceeded our carrying value. For this test, we assessed various assumptions, events and circumstances that would have affected our estimated fair value as compared to our baseline "step 1" fair value measurement performed May 1, 2020.

7. 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, removal of certain pipelines known to contain PCB contamination, 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 have a significant obligation associated with the decommissioning of two hydro facilities located in Indiana. These hydro facilities have an indeterminate life, and as such, no asset retirement obligation has been recorded.

Changes in our liability for asset retirement obligations for the years 2022 and 2021 are presented in the table below.

(in millions)		**2022**	2021	
Beginning Balance		**$ 391.**	$ 414.	
	Accretion recorded as a regulatory liability	**12.9**	12.6	
	Additions	**9.5**	23.2	
	Settlements	**(22.3)**	(11.2)	
	Change in estimated cash flows	**2.2**	(47.6)	(1)
Ending Balance		**$ 393.**	$ 391.	

(1) The change in estimated cash flows for 2021 is primarily related to changes in cost estimates for electric generating stations.

Certain non-legal costs of removal that 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.

8. Regulatory Matters

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 if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can 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 Consolidated Balance Sheets 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 our regulatory assets each period.

Regulatory assets were comprised of the following items.

At December 31, *(in millions)*		**2022**	2021
Regulatory Assets			
	Unrecognized pension and other postretirement benefit costs (see Note 11)	**$ 445.**	$ 396.
	Retired coal generating stations	**744**	803.9
	Losses on commodity price risk programs (see Note 9)	**10**	9.6
	Depreciation	**20.1**	17.9
	Post-in-service carrying charges	**13**	12
	Under-recovered gas and fuel costs (see Note 1-I)	**27.6**	20.9
	Renewable energy investments (See Note 1-S and Note 4)	**37.7**	18.5
	Other	**34.2**	34.4
Total Regulatory Assets		**$ 1,331.**	$ 1,314.
Less: Current Portio		**114.7**	100.5
Total Noncurrent Regulatory Assets		**$ 1,217.**	$ 1,213.

Regulatory liabilities were comprised of the following items.

At December 31, *(in millions)*		**2022**	2021
Regulatory Liabilities			
	Regulatory effects of accounting for income taxes (see Note 1-N and Note 10)	**$ 470.**	$ 510.
	Cost of removal (see Note 7)	**312.5**	385.8
	Gains on commodity price risk programs (see Note 9)	**90**	34.2
	Other	**50.5**	25.2
Total Regulatory Liabilities		**$ 923.**	$ 955.
Less: Current Portio		**91.5**	68.3
Total Noncurrent Regulatory Liabilities		**$ 832.**	$ 887.

Regulatory assets, including under-recovered gas costs and depreciation, of approximately $503.3 million and $445.6 million as of December 31, 2022 and 2021, respectively, are not earning a return on investment. These costs are recovered over a remaining life, the longest of which is 50 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. We defer these gains or losses as a regulatory asset in accordance with regulatory orders or as a result of regulatory precedent, to be recovered through base rates.

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 Unites 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. Our December 2019 electric rate case order allows for the recovery of, and on, the net book value of the stations by the end of 2032 and implements a revenue credit for the retired units. The credit is based on the difference between the net book value of Units 14 and 15 upon retirement and the last base rate case proceeding. The credit will be reset when new base rates are determined. See Note 5, "Property, Plant and Equipment," for further details.

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.

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, 2022 and 2021, depreciation of $19.7 million and $16.9 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*."

Under-recovered gas and fuel costs. Represents the difference between the costs of gas and fuel and the recovery of such costs in revenue and is used to adjust future billings for such deferrals on a basis consistent with applicable IURC tariff provisions. Recovery of these costs is achieved 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. These amounts will be collected through base rates over the life of the renewable generating assets to which they relate. Refer to Note 1-S, "VIEs and Allocation of Earnings," for additional information. Renewable energy formation and developer costs are also included in this regulatory asset.

Liabilities:

Regulatory effects of accounting for income taxes. Represents amounts owed to customers for deferred taxes collected at a higher rate than the current statutory rates and liabilities associated with accelerated tax deductions owed to customers that are established during the rate making process. Balance includes excess deferred taxes recorded upon implementation of the TCJA in December 2017, net of amounts amortized through 2022.

Cost of removal. Represents anticipated costs of removal that have been, and continue to be, included in depreciation rates and collected in customer 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.

Change in Accounting Estimate

As part of the NIPSCO Gas Settlement and Stipulation Agreement filed on March 2, 2022, we agreed to change the depreciation methodology for the calculation of depreciation rates, which reduces depreciation expense and subsequent revenues and cash flows. An order was received on July 27, 2022 approving the rate case and rates were effective as of September 1, 2022. We have proposed a similar change in depreciation methodology in our pending electric base rate case.

Regulatory deferral related to renewable energy investments

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. Refer to Note 4, "Variable Interest Entities," and Note 5, "Property, Plant and Equipment," for additional information.

FAC Adjustment
As ordered by the IURC on June 15, 2022, we are required to refund to customers $8.0 million of over-collected fuel costs. The remaining refund is recorded as a regulatory liability on the Consolidated Balance Sheets and is expected to be refunded in 2023.

COVID-19 Regulatory Filings
In response to the COVID-19 pandemic, we received approval from the IURC to defer incremental bad debt expense and the costs to implement the requirements of the COVID-19 related order. Our regulatory asset balance is $2.1 million as of December, 2022 and was $2.2 million as of December 31, 2021. All pandemic-related regulatory actions have expired or have been lifted.

Rate Case Settlement
On March 10, 2023, we, and certain parties to the rate case, filed a settlement agreement that, if approved, will resolve all issues in the rate case. If approved by the IURC, we will be authorized to increase annual revenues by $291.8 million. We anticipate receipt of an order on the settlement agreement by August 23, 2023 with implementation of new rates effective September 1, 2023. At this time, there may be parties that oppose the settlement. Opposing parties have until March 31, 2023 to file any opposition to the proposed settlement.

9. Risk Management Activities

We are exposed to certain risks relating 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, 2022		**December 31, 2021**	
(in millions)	**Assets**	**Liabilities**	**Assets**	**Liabilities**
Current Derivatives not designated as hedging instruments (1)	**$ 18.**	**$ 1.**	$ 10.	$ 0.
Noncurrent Derivatives not designated as hedging instruments (2)	**$ 66.**	**$ 1.**	$ 13.	$ 7.

(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" on the Consolidated Balance Sheets.

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.

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, 2022, the remaining terms of these instruments range from one to five 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. These instruments are not designated as hedging instruments. Refer to Note 8, "Regulatory Matters," for additional information.

There were no amounts excluded from effectiveness testing for derivatives in cash flow hedging relationships at December 31, 2021 and 2020.

Our derivative instruments measured at fair value as of December 31, 2022 and 2021 do not contain any credit-risk-related contingent features. Cash flows for derivative financial instruments are generally classified in cash flows from operating activities.

10. Income Taxes

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

Year Ended December 31, *(in millions)*	**2022**	2021	2020
Income Taxes			
Current			
Federal	**$ 35.**	$ 29.	$ 35.
State	**8**	—	—
Total Current	**43.9**	29.5	35.3
Deferred			
Federal	**19.2**	26.2	22.8
State	**6**	21.1	11.5
Total Deferred	**25.2**	47.3	34.3
Deferred Investment Credits	**(0.3)**	(0.4)	(0.4)
Income Taxes	**$ 68.**	$ 76.	$ 69.

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)*	**2022**		2021		2020	
Book income before income taxes	**$ 397.**		$ 410.		$ 358.	
Tax expense at statutory federal income tax rate	**83.4**	**21.0%**	86.1	21.0%	75.4	21.0%
Increases (reductions) in taxes resulting from:						
State income taxes, net of federal income tax benefit	**12.2**	**3.1**	16.6	4	9.1	2.5
Regulatory treatment of depreciation differences	**(25.4)**	**(6.4)**	(24.4)	(5.9)	(21.5)	(6.0)
Nondeductible expenses	**(2.5)**	**(0.6)**	(1.9)	(0.5)	(2.0)	(0.5)
Other adjustments	**1.1**	**0.2**	—	—	8.2	2.3
Income Taxes	**$ 68.**	**17.3%**	$ 76.	18.6%	$ 69.	19.3%

The effective income tax rates were 17.3%, 18.6% and 19.3% in 2022, 2021 and 2020, respectively. There was no material change in the effective tax rate from 2022 versus 2021 or from 2021 versus 2020.
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)*	**2022**	2021
Deferred Tax Liabilities		
Accelerated depreciation and other property differences	**$ 1,181.**	$ 1,132.
Other regulatory assets	**138.5**	120.1
Total Deferred Tax Liabilities	**1,319.7**	1,252.3
Deferred Tax Asset		
Other regulatory liabilities and deferred investment tax credits (including TCJA)	**145.6**	135.3
Net operating loss carryforward	**127.6**	126.5
Pensions and other postretirement/postemployment benefits	**68**	60.3
Other, net	**19**	29.2
Total Deferred Tax Assets	**360.2**	351.3
Net Deferred Tax Liabilities	**$ 959.**	$ 901.

At December 31, 2022, we have federal net operating loss carryforwards of $119.5 million (tax effected). The federal net operating loss carryforwards are available to offset taxable income that will begin to expire in 2036. We believe it is more likely than not that we will realize the benefit from the federal net operating loss carryforwards.

We also have $8.1 million (tax effected net of federal benefit) of state net operating loss carryforwards that will begin to expire in 2028. We believe it is more likely than not that we will realize the benefit from state net operating loss carryforwards.

We are subject to income taxation in the United States, the state of Indiana and several other state jurisdictions.

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, 2022, tax years through 2021 have been audited and are effectively closed to further assessment. The audit of tax year 2022 under the CAP program is expected to be completed in 2023.

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, 2022, there were no open state income tax audits.

11. Pension and Other Postretirement 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 of our retired employees. The majority of 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. 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 (fixed income) as the funded status of the plans' increase.

As of December 31, 2022 and December 31, 2021, the acceptable minimum and maximum ranges established by the policy for the pension and other postretirement benefit plans are as follows.

December 31, 2022	Defined Benefit Pension Plan		Postretirement Benefit Plan	
Asset Category	**Minimum**	**Maximum**	**Minimum**	**Maximum**
Domestic Equities	7%	27%	0%	55%
International Equities	3%	13%	0%	25%
Fixed Income	69%	81%	20%	100%
Real Estate	0%	3%	0%	0%
Private Equity	0%	3%	0%	0%
Short-Term Investments	0%	10%	0%	10%

December 31, 2021	Defined Benefit Pension Plan		Postretirement Benefit Plan	
Asset Category	**Minimum**	**Maximum**	**Minimum**	**Maximum**
Domestic Equities	7%	27%	0%	55%
International Equities	3%	13%	0%	25%
Fixed Income	69%	81%	20%	100%
Real Estate	0%	3%	0%	0%
Private Equity	0%	3%	0%	0%
Short-Term Investments/Other	0%	10%	0%	10%

The actual Pension Plan and Postretirement Plan Asset Mix at December 31, 2022 and December 31, 2021 are as follows.

	Defined Benefit Pension Assets [(1)]	December 31, 2022	Postretirement Benefit Plan Assets	December 31, 2022
Asset Class *(in millions*	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	$ 156.	16.2%	$ 6.	51.7%
International Equities	80.8	8.4%	0.7	5.6%
Fixed Income	681.8	70.6%	4.9	39.9%
Real Estate	3.4	0.3%	—	0%
Cash/Other	43	4.5%	0.3	2.8%
Total	$ 965.	100%	$ 12.	100%

(1) Total includes accrued dividends and pending trades with brokers.

	Defined Benefit Pension Assets [(1)]	December 31, 2021	Postretirement Benefit Plan Assets	December 31, 2021
Asset Class *(in millions*	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	$ 218.	16.4%	$ 7.	53.1%
International Equities	101.7	7.6%	0.8	5.5%
Fixed Income	932	69.7%	5.8	39.5%
Real Estate	25.1	1.9%	—	0%
Cash/Other	58.7	4.4%	0.3	1.9%
Total	$ 1,336.	100%	$ 14.	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, our allocation within the Master Trust and other postretirement benefits investment assets at fair value as of December 31, 2022 and 2021. Assets are classified in their entirety based on the observability of inputs used in determining the fair value measurement. We are allocated a portion of the investment assets at fair value classified within Level 3 of the Master Trust for disclosure purposes based upon our ownership percentage of the total Master Trust. Our allocation of investment assets at fair value classified within Level 3 were zero as of both December 31, 2022 and 2021, respectively. Such amounts were zero of our total investment in the Master Trust and other postretirement benefits' total investments as reported on the statements of net assets available for benefits at fair value as of both December 31, 2022 and 2021.

We use the following valuation techniques to determine fair value. For the year ended December 31, 2022, there were no significant changes to valuation techniques to determine the fair value of our pension and other postretirement benefits' assets.

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 hold underlying investments that have prices derived from quoted prices in active markets and 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, 2022:

(in millions)	December 31, 2022	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	$ 1.	$ 1.	$ 0.	$
Equity securities				
International equities	0.3	0.3	—	—
Fixed income securities				
Government	214.7	—	214.7	—
Corporate	276.8	—	276.8	—
Mortgages / Asset-backed securities	1.6	—	1.6	—
Other	1.3	1.3	—	—
Mutual funds				
U.S. multi-strategy	66.1	66.1	—	—

U.S. multi-strategy	[illegible]	[illegible]	—	—
International equities	19.7	19.7	—	—
Fixed income	0.1	0.1	—	—
Private equity limited partnerships				
U.S. multi-strategy [1]	4.3	—	—	—
International multi-strategy [2]	1.5	—	—	—
Distressed opportunities	0.1	—	—	—
Real estate	3.4	—	—	—
Commingled funds [3]				
Short-term money markets	31.4	—	—	—
U.S. equities	90.8	—	—	—
International equities	60.8	—	—	—
Fixed income	187.2	—	—	—
Pension plan assets subtotal	$ 961.	$ 88.	$ 493.	$
Other postretirement benefit plan assets:				
Mutual funds				
U.S. equities	$ 6.	$ 6.	$	$
International equities	0.7	0.7	—	—
Fixed income	4.9	4.9	—	—
Other postretirement benefit plan assets subtotal	$ 11.	$ 11.	$	$
Due to brokers, net [4]	(1.1)	—	—	—
Receivables/payables	0.3	—	—	—
Accrued investment income/dividends	5.2	—	—	—
Total pension and other postretirement benefit plan assets	$ 978.	$ 100.	$ 493.	$

[1] This class includes limited partnerships/fund of funds that invest in a diverse portfolio of private equity strategies, including buy-outs, growth capital, special situations and secondary markets, primarily in the United States.
[2] This class includes limited partnerships/fund of funds 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.
[3] 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.
[4] This category 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, 2022.

(in millions)	Fair Value	Redemption Frequency	Redemption Notice Period
Commingled Funds			
Short-term money markets	$ 31.	Daily	1 day
U.S. equities	90.8	Daily	1-5 days
International equities	60.8	Monthly	10-30 days
Fixed income	187.2	Daily	3 days
Private Equity and Real Estate Limited Partnerships [1]	9.3	N/A	N/A
Total	$ 379.		

[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, 2021:

(in millions)	December 31, 2021	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	$ 6.	$ 6.	$ 0.	$
Equity securities				
International equities	0.3	0.3	—	—
Fixed income securities				
Government	261.1	—	261.1	—
Corporate	435.4	—	435.4	—
Mutual funds				
U.S. multi-strategy	86.6	86.6	—	—
International equities	26.1	26.1	—	—
Private equity limited partnerships				
U.S. multi-strategy [1]	7.4	—	—	—
International multi-strategy [2]	3	—	—	—
Distressed opportunities	0.1	—	—	—
Real estate	25.1	—	—	—
Commingled funds [3]				
Short-term money markets	37.1	—	—	—
U.S. equities	132	—	—	—
International equities	75.3	—	—	—
Fixed income	235.5	—	—	—
Pension plan assets subtotal	$ 1,331.	$ 119.	$ 696.	$
Other postretirement benefit plan assets:				
Mutual funds				
U.S. equities	$ 7.	$ 7.	$	$
International equities	0.8	0.8	—	—
Fixed income	5.7	5.7	—	—
Other postretirement benefit plan assets subtotal	$ 14.	$ 14.	$	$
Due to brokers, net [4]	(1.1)	—	—	—
Receivables/payables	0.3	—	—	—
Accrued investment income/dividends	5.3	—	—	—
Total pension and other postretirement benefit plan assets	$ 1,350.	$ 133.	$ 696.	$

[1] This class includes limited partnerships/fund of funds that invest in a diverse portfolio of private equity strategies, including buy-outs, venture capital, growth capital, special situations and secondary markets, primarily in the United States.
[2] This class includes limited partnerships/fund of funds that invest in a diverse portfolio of private equity strategies, including buy-outs, venture capital, growth capital, special situations and secondary markets, primarily outside the United States.
[3] 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.
[4] This category 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, 2021.

(in millions)	Fair Value	Redemption Frequency	Redemption Notice Period
Commingled Funds			
Short-term money markets	$ 37.	Daily	1 day
U.S. equities	132	Daily	1-5 days
International equities	75.3	Monthly	10-30 days
Fixed income	235.4	Daily	3 days
Private Equity and Real Estate Limited Partnerships [1]	13.8	N/A	N/A
Total	$ 493.		

[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)	2022	2021	2022	2021
Change in projected benefit obligation [1]				
Benefit obligation at beginning of year	**$ 1,236.**	$ 1,361.	**$ 291.**	$ 309.
Service cost	**18.5**	19.6	**3.7**	3.4
Interest cost	**26**	21.7	**6.3**	5.2
Plan participants' contributions	**—**	—	**1.6**	1.7
Plan amendments	**0.2**	—	**1.5**	—
Actuarial gain [2]	**(230.3)**	(60.3)	**(45.6)**	(9.0)
Benefits paid	**(101.1)**	(105.7)	**(20.1)**	(19.9)
Projected benefit obligation at end of year	**$ 950.**	$ 1,236.	**$ 238.**	$ 291.
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 1,336.**	$ 1,408.	**$ 14.**	$ 12.
Actual return on plan assets	**(269.1)**	33.6	**(2.4)**	1.8
Employer contributions	**—**	—	**18.5**	18.3
Plan participants' contributions	**—**	—	**1.6**	1.7
Benefits paid	**(101.1)**	(105.7)	**(20.1)**	(19.9)
Fair value of plan assets at end of year	**$ 965.**	$ 1,336.	**$ 12.**	$ 14.
Funded status at end of year	**$ 15.**	$ 99.	**$ (226.2**	$ (276.4
Amounts recognized on the Consolidated Balance Sheets consist of:				
Noncurrent assets	**$ 15.**	$ 99.	**$**	$
Current liabilities	**—**	—	**(7.0)**	(4.4)
Noncurrent liabilities	**—**	—	**(219.2)**	(272.0)
Net amount recognized at end of year [3]	**$ 15.**	$ 99.	**$ (226.2**	$ (276.4
Amounts recognized in accumulated other comprehensive income or regulatory asset/liability [4]				
Unrecognized prior service cost/(credit)	**$ 0.**	$ 0.	**$ (10.4**	$ (14.9
Unrecognized actuarial loss	**421.7**	334	**33.3**	77.4
Net amount recognized at end of year	**$ 422.**	$ 334.	**$ 22.**	$ 62.

[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 gain was primarily driven by an increase in discount rates. The postretirement benefit gain was also primarily driven by an increase in discount 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 $445.2 million as of December 31, 2022 and $396.9 million as of December 31 2021 that would otherwise have been recorded to accumulated other comprehensive income (loss).

Our accumulated benefit obligation for our pension plan was $939.4 million and $1,218.6 million as of December 31, 2022 and 2021, respectively. The accumulated benefit obligation as of a 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 $15.9 million at December 31, 2022 compared to being overfunded by $99.4 million at December 31, 2021. The decline in funded status was due primarily to unfavorable asset returns. We did not contribute to our pension plan in either 2022 or 2021.

Our other postretirement benefit plans were underfunded by $226.2 million at December 31, 2022 compared to being underfunded by $276.4 million at December 31, 2021. The improvement in funded status was primarily due to increased discount rates offset by unfavorable asset returns. We contributed $18.5 million and $18.3 million to our other postretirement benefits plans in 2022 and 2021, 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**	
	2022	2021	**2022**	2021
Weighted-average assumptions to determine benefit obligation				
Discount rate	**5.15%**	2.81%	**5.17%**	2.87%
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	**6.69%**	6.22%
Ultimate trend	**N/A**	N/A	**4.75%**	4.50%
Year ultimate trend reached	**N/A**	N/A	**2032**	2030

We expect to make no contributions to our pension plan and expect to make contributions of approximately $19.2 million to our postretirement medical and life plans in 2023.

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)		
2023	$ 91.	$ 19.
2024	88.7	18.9
2025	85.5	18.4
2026	81.6	18.2
2027	80	18.2
2028-2032	369.6	90.5

The following table provides the components of the plans' net periodic benefits costs for each of the three years ended December 31, 2022, 2021 and 2020.

	Pension Benefits			**Other Postretirement Benefits**		
(in millions)	**2022**	2021	2020	**2022**	2021	2020
Components of Net Periodic Benefit Cost (Income) [1]						
Service cost	**$ 18.**	$ 19.	$ 18.	**$ 3.**	$ 3.	$ 3.
Interest cost	**26**	21.7	34.1	**6.3**	5.2	8.1
Expected return on assets	**(61.9)**	(70.1)	(70.4)	**(1.0)**	(0.8)	(0.8)
Amortization of prior service cost/(credit)	**0.1**	0.1	0.2	**(2.9)**	(2.9)	(3.0)
Recognized actuarial loss	**12.9**	15.3	20.9	**1.8**	3.2	3
Total Net Periodic Benefit Cost (Income)	**$ (4.4**	$ (13.4	$ 3.	**$ 7.**	$ 8.	$ 10.

[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**		
	2022	2021	2020	**2022**	2021	2020
Weighted-Average Assumptions to Determine Net Periodic Benefit Cost						
Discount rate - service cost	**3.14%**	2.89%	3.47%	**3.26%**	3.08%	3.59%
Discount rate - interest cost	**2.18%**	1.67%	2.71%	**2.24%**	1.74%	2.77%
Expected long-term rate of return on plan assets	**4.80%**	5.20%	5.70%	**6.94%**	6.85%	6.88%
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 4.80% and 6.94% rate of return on pension and other postretirement plan assets, respectively, for our calculation of 2022 pension benefits and other postretirement benefits costs. These rates are primarily based on asset mix and historical rates of return and were adjusted in the current year due to anticipated 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)	**2022**	2021	**2022**	2021
Other Changes in Plan Assets and Projected Benefit Obligations Recognized in Regulatory Asset or Liability				
Net prior service cost	**$ 0.**	$	**$ 1.**	$
Net actuarial loss (gain)	**100.7**	(23.8)	**(42.2)**	(10.0)
Less: amortization of prior service (credit)/cos	**(0.1)**	(0.1)	**2.9**	2.9
Less: amortization of net actuarial gai	**(12.9)**	(15.3)	**(1.8)**	(3.2)
Total Recognized in Regulatory Asset or Liability	**$ 87.**	$ (39.2	**$ (39.6**	$ (10.3
Amount Recognized in Net Periodic Benefits Cost and Regulatory Asset or Liability	**$ 83.**	$ (52.6	**$ (31.7**	$ (2.2

12. Equity

Noncontrolling Interest in Consolidated Subsidiaries. As of December 31, 2022 and 2021, NIPSCO and tax equity partners have completed their cash contributions into the Indiana Crossroads Wind and Rosewater joint ventures and made initial cash contributions into the Indiana Crossroads Solar joint venture. 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 total equity on the Consolidated Balance Sheets. Refer to Note 4, "Variable Interest Entities," for more information.

13. Long-Term Debt

Our long-term debt as of December 31, 2022 and 2021 is as follows.

As of December 31, (in millions)	**2022**	2021
Medium-Term Notes —		
7.40% due August 30, 2022	**$**	$ 10.
7.69% due June 6, 2027	**20**	20
7.69% due June 27, 2027	**33**	33
7.16% due August 4, 2027	**5**	5
Total Medium-Term Notes	**58**	68
Intercompany Notes —		
6.53% due June 6, 2023	**80**	80
5.99% due September 18, 2025	**75**	75
6.41% due December 4, 2029	**120**	120
4.55% due June 26, 2035	**93.8**	93.8
4.53% due December 21, 2037	**55**	55
5.17% due July 26, 2038	**89**	89
4.83% due December 19, 2042	**95**	95
5.43% due July 24, 2043	**95**	95
4.99% due February 15, 2044	**66**	66
4.35% due December 16, 2044	**82**	82
4.99% due June 26, 2045	**93.7**	93.7
4.701% due December 30, 2045	**91**	91
4.364% due December 30, 2046	**210**	210
4.161% due June 30, 2047	**40**	40
4.112% due September 29, 2047	**162.5**	162.5
4.53% due June 29, 2048	**450**	450
3.568% due September 30, 2049	**150**	150
3.174% due June 30, 2050	**208**	208
3.272% due June 30, 2051	**175**	175
5.081% due June 30, 2052	**225**	—
5.650% due December 30, 2052	**210**	—
Total Intercompany Notes	**2,866.0**	2,431.0
Total Finance Leases	**16.6**	18.7
Unamortized Discounts	**(0.1)**	(0.1)
Total Long-Term Debt	**$ 2,940.**	$ 2,517.

Details of our 2022 long-term debt related activity are summarized below.

- On June 30, 2022 we issued $225.0 million of 5.081% intercompany notes.
- On December 31, 2022, we issued $210.0 million of 5.650% intercompany notes.

Details of our 2021 long-term debt related activity are summarized below.

- On June 30, 2021, we issued $175.0 million of 3.272% intercompany notes

See Note 17-A, "Contractual Obligations," for the outstanding long-term debt maturities at December 31, 2022.

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

14. Short-Term Borrowings

We satisfy our liquidity requirements primarily through internally generated funds and through intercompany borrowings from the NiSource Money Pool. We may borrow a maximum of $1.0 billion through the NiSource Money Pool as approved by the FERC. As of December 31, 2022, we had $530.7 million of short-term NiSource Money Pool borrowings outstanding at an interest rate of 2.60%. As of December 31, 2021, we had $414.4 million of short-term NiSource Money Pool borrowings outstanding at an interest rate of 0.19%. Amounts received from the NiSource Money Pool are reflected in "Short-term borrowings - affiliated" on the Consolidated Balance Sheets.

We may also deposit funds into the NiSource Money Pool. As of December 31, 2022 and December 31, 2021, we had $28.3 million and zero, respectively, of short-term NiSource Money Pool deposits due. Amounts invested in the NiSource Money Pool are reflected in “Accounts receivable - 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 16, 2023 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, 2022, the maximum amount of debt that could be recognized related to our accounts receivable program is $225.0 million.

We had short-term borrowings of $207.2 million and zero related to the securitization transactions as of December 31, 2022 and December 31, 2021, respectively.

For the years ended December 31, 2022 and 2021, $207.2 million and zero, respectively, were recorded as cash flows from 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 $4.1 million, $0.6 million and $2.3 million for the years ended December 31, 2022, 2021 and 2020, respectively. We remain responsible for collecting on the receivables securitized, and the receivables cannot be transferred to another party.

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

15. 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 and fleet vehicles. Our corporate and field office leases have remaining lease terms between 1 and 21 years with options to renew the leases for up to 25 years. We lease railcars to transport coal to and from our electric generation facilities. Our railcars are specifically identified in the lease agreements and have 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 on 1-year terms, after which we have the option to extend on a month-to-month basis or terminate with written notice. ROU assets and liabilities on our Consolidated Balance Sheets do not include obligations for possible fleet vehicle 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 non-lease 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, 2022 and December 31, 2021 are presented in the table below. These costs include both amounts recognized in expense and amounts capitalized as part of the cost of another asset. Income statement presentation for these costs, when ultimately recognized on the income statement, is also included.

Year Ended December 31, *(in millions)*	Income Statement Classification	**2022**	2021
Finance lease cost			
Amortization of right-of-use assets	Depreciation and amortization	**$ 1.**	$ 1.
Interest on lease liabilities	Other, net	**0.5**	1.1
Total finance lease cost		**2.3**	2.9
Operating lease cost	Operating and maintenance	**3.3**	4.1
Total lease cost		**$ 5.**	$ 7.

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	**2022**	**2021**
Assets			
Finance leases	Net Property, Plant and Equipment	**$ 21.**	$ 23.
Operating leases	Deferred charges and other	**10.6**	7
Total leased assets		**$ 32.**	$ 30.
Liabilities			
Current			
Finance leases	Current portion of long-term debt	**$ 2.**	$ 2.
Operating leases	Other accruals	**1.3**	1.8
Noncurrent			
Finance leases	Long-term debt, excluding amounts due within one year	**14.3**	16.5
Operating leases	Other noncurrent liabilities	**9.4**	5.4
Total lease liabilities		**$ 27.**	$ 25.

Other pertinent information related to leases was as follows.

Year Ended December 31, *(in millions)*	**2022**	**2021**
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows used for finance leases	$ 0.	$ 0.
Operating cash flows used for operating leases	3.3	3.9
Financing cash flows used for finance leases	2.2	2.2
Right-of-use assets obtained in exchange for lease obligations		
Finance leases	$	$ 4.
Operating leases	6.9	5.1

at December 31, *(in millions)*	**2022**	**2021**
Weighted-average remaining lease term (years)		
Finance leases	12.2	13.3
Operating leases	5.9	7.2
Weighted-average discount rate		
Finance leases	1.8	1.8
Operating leases	3.5	3.0

Maturities of our lease liabilities as of December 31, 2022 were as follows:

As of December 31, 2022 *(in millions)*	Total	Finance Leases	Operating Leases
2023	$ 5.	$ 2.	$ 2.
2024	4.9	2.7	2.2
2025	4.8	2.7	2.1
2026	4.5	2.8	1.7
2027	4.1	2.8	1.3
Thereafter	6.6	4.7	1.9
Total lease payments	30.4	18.4	12
Less: Imputed interes	(3.1)	(1.8)	(1.3)
Total	$ 27.	$ 16.	$ 10.
Reported as of December 31, 2022			
Short-term lease liabilities	3.6	2.3	1.3
Long-term lease liabilities	23.7	14.3	9.4
Total lease liabilities	$ 27.	$ 16.	$ 10.

16. 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, 2022 and December 31, 2021.

Recurring Fair Value Measurements December 31, 2022 *(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, 2022
Risk Management Assets	$	$ 84.	$	$ 84.
Risk Management Liabilities	$	$ 3.	$	$ 3.

Recurring Fair Value Measurements December 31, 2021 *(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, 2021
Risk Management Assets	$	$ 24.	$	$ 24.
Risk Management Liabilities	$	$ 7.	$	$ 7.

Risk Management Assets and Liabilities. Risk management assets and liabilities include commodity exchange-traded and non-exchange-based derivative contracts.

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 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 instruments are 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.

Credit risk is considered in the fair value calculation of derivative instruments that are not exchange-traded. Credit exposures are adjusted to reflect collateral agreements which reduce exposures. As of December 31, 2021 and 2020, 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 financial instruments.

We have entered into long-term forward natural gas purchase instruments to lock in a fixed price for our 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 9, "Risk Management Activities."

There were no material items in the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis as of December 31, 2022 and 2021.

Non-recurring Fair Value Measurements

We measure the fair value of certain assets on a non-recurring basis, typically annually or when events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable.

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. As of December 31, 2022 and 2021, 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)*	**2022**	**2022**	2021	2021
Long-term debt (including current portion)	**$ 2,940.**	**$ 2,547.**	$ 2,517.	$ 2,931.

17. Other Commitments and Contingencies

A. Contractual Obligations. We have 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, 2022 and their maturities were as follows.

(in millions)	Total	2023	2024	2025	2026	2027	After
Long-term debt	$ 2,924.	$ 80.	$	$ 75.	$	$ 58.	$ 2,711.
Interest payments on long-term debt	2,931.8	135.1	132.4	131.5	127.9	126.7	2,278.2
Finance leases (1)	16.6	2.7	2.6	2.5	2.5	2.5	3.8
Operating leases (2)	30	6	5.9	5.8	5.4	5	1.9
Energy commodity contracts	233.6	121.6	76	36	—	—	—
Pipeline service obligations	216	98.9	70.7	24.4	9.6	9.5	2.9
Other service obligations	5.8	3.5	1.3	1	—	—	—
Other liabilities (3)	576.5	535.5	5.6	5.2	5.5	5.5	19.2
Total Contractual Obligations	$ 6,934.	$ 983.	$ 294.	$ 281.	$ 150.	$ 207.	$ 5,017.

(1) Finance lease payments shown above are inclusive of interest totaling $1.8 million.
(2) Operating lease payments shown above are inclusive of interest totaling $1.3 million. Operating lease balances do not include amounts for fleet leases that can be renewed beyond the initial lease term. While we have the ability to renew these leases beyond the initial term we are not reasonably certain (as that term is defined in ASC 842) to do so as they are renewed month-to-month after the first year.
(3) Other liabilities shown above are inclusive of Rosewater, Indiana Crossroads Wind and Indiana Crossroads Solar Developer payments due in 2023.

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 purchase obligations are for the purchase of physical quantities of natural gas, electricity and coal. Our service agreements encompass a broad range of business support and maintenance functions which are generally described below.

We have entered into various energy commodity contracts to purchase physical quantities of natural gas, electricity and coal. 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, 2022.

We have power purchase arrangements representing a total of 500 MW of wind power, with contracts expiring between 2024 and 2040. No minimum quantities are specified within these agreements due to the variability of electricity generation from wind, so no amounts related to these contracts are included in the table above. Upon early termination of one of these agreements 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 from 2023 to 2038, require us to pay fixed monthly charges.

We have contracts with three major rail operators providing for coal transportation services for which there are certain minimum payments. These service contracts extend for various periods 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, 2022 and 2021, their guarantees for multiple BTAs totaled $841.6 million and $288.9 million, respectively. The amount of each guaranty will decrease upon the completion of the construction of the facilities. See "-E. Other Matters – Generation Transition," below for more information.

C. Legal Proceedings. We are party to certain claims and legal proceedings arising in the ordinary course of business, none of which are deemed to be individually material at this time. Due to the inherent uncertainty of litigation, there can be no assurance that the resolution of any particular claim or proceeding would not have a material adverse effect on our results of operations, financial position or liquidity. If one or more of such 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.

FERC Investigation. In April 2022, we were notified that the FERC Office of Enforcement ("OE") is conducting an investigation of an industrial customer for allegedly manipulating the MISO Demand Response ("DR") market. The customer, along with us, are both cooperating with the investigation. If the OE ultimately were to seek to require the customer to repay any portion of the DR revenue received from MISO, it is reasonably possible that the OE would also seek to require us to disgorge administrative fees and foregone margin charges that we collected pursuant to our own IURC-approved tariff. We currently estimate the maximum amount of our disgorgement exposure to be $9.7 million, and the investigation is still ongoing. We intend to seek indemnification under our agreements with the customer for any liability we incur related to this matter.

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 we are, in all material respects, in 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 a majority of environmental assessment and remediation costs and asset retirement costs, further described below, to be recoverable through customer rates. See Note 8, "Regulatory Matters," for additional details.

As of December 31, 2022 and 2021, we had recorded a liability of approximately $38.7 million and $40.0 million, respectively, to cover environmental remediation at various sites. This liability is included in "Legal and environmental" and "Other noncurrent liabilities" 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. See Note 7, "Asset Retirement Obligations," for a discussion of all obligations, including those discussed below.

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 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 be material to the Condensed Consolidated Financial Statements.

MGP. We maintain a program to identify and investigate former MGP sites where we 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 noted as a result of the refresh completed as of June 30, 2022. Our total estimated liability related to the facilities subject to remediation was $33.2 million and $34.2 million at December 31, 2022 and 2021, respectively. The liability represents our best estimate of the probable cost to remediate the MGP sites. We believe that it is reasonably possible that remediation costs could vary by as much as $6.5 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 in the EPA's final rule for the regulation of CCRs. The CCR rule also resulted in 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.

Name of Respondent:	This report is:	Date of Report:	Year/Period of Report
Northern Indiana Public Service Company LLC	(1) ☑ An Original (2) ☐ A Resubmission	04/17/2023	End of: 2022/ 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						(13,731)	(13,731)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income						(61,441)	(61,441)		
3	Preceding Quarter/Year to Date Changes in Fair Value									
4	Total (lines 2 and 3)						(61,441)	(61,441)	325,704,136	325,642,695
5	Balance of Account 219 at End of Preceding Quarter/Year						(75,172)	(75,172)		
6	Balance of Account 219 at Beginning of Current Year						(75,172)	(75,172)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income						(26,985)	(26,985)		
8	Current Quarter/Year to Date Changes in Fair Value									
9	Total (lines 7 and 8)						(26,985)	(26,985)	327,232,579	327,205,594
10	Balance of Account 219 at End of Current Quarter/Year						(102,157)	(102,157)		

E. Other Matters.

Generation Transition. We have executed several PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per MWh. Each facility supplying the energy will have an associated nameplate capacity, and payments under the PPAs will not begin until the associated generation facility is constructed by the owner/seller. We have also executed several BTAs with developers to construct renewable generation facilities. Our purchase requirement under each respective BTA is dependent on satisfactory approval of the BTA by the IURC, successful execution of an agreement with a tax equity partner and timely completion of construction. We have either received IURC approval for all of our BTAs and PPAs. We, and the tax equity partner, for each respective BTA, are both obligated to make cash contributions to the JV that acquires the project at the date construction is substantially complete. Certain agreements require us to make partial payments upon the developer's completion of significant construction milestones. Once the tax equity partner has earned their negotiated rate of return and we have reached the agreed upon contractual date, we have the option to purchase at fair market value the remaining interest in the JV from the tax equity partner.

18. Other, Net

Year Ended December 31, *(in millions)*	2022	2021	2020
Interest expense on short-term debt	**$ (10.4**	$ (1.1	$ (4.0
Interest income	**0.2**	—	0.1
AFUDC equity	**13**	19.3	8.1
Pension and other postretirement non-service costs [(1)]	**18.8**	28.4	7.9
Sale of emission reduction credits	**—**	—	4.4
Miscellaneous	**3.4**	(2.0)	(0.1)
Total Other, Net	**$ 25.**	$ 34.	$ 16.

(1) See Note 11, "Pension and Other Postretirement Benefits," for additional information.

19. Supplemental Disclosures of Cash Flow Information

The following table provides additional information regarding our Consolidated Statements of Cash Flows for the years ended December 31, 2022, 2021 and 2020.

Year Ended December 31, *(in millions)*	2022	2021	2020
Non-cash transactions:			
Capital expenditures included in current liabilities	**$ 164.**	$ 150.	$ 100.
Assets acquired under a finance lease	**—**	4.9	20.6
Assets acquired under an operating lease	**6.9**	5.1	2.7
Reclassification of other property to regulatory assets [(1)]	**—**	607.6	—
Assets recorded for asset retirement obligations [(2)]	**4.5**	33.3	96.8
Obligations to developer at formation of joint venture [(3)]	**—**	277.5	69.7
Schedule of interest and income taxes paid (refunded):			
Cash paid for interest on long-term debt, net of interest capitalized - affiliated	**$ 119.**	$ 107.	$ 106.
Cash paid for interest on long-term debt, net of interest capitalized - unaffiliated	**6**	8.5	8.5
Cash paid for interest on finance leases	**0.5**	1.1	—
Cash paid/(refunded) to NiSource for income taxes	**30.8**	(12.0)	—

(1) See Note 8, "Regulatory Matters," for additional information.
(2) See Note 7, "Asset Retirement Obligations," for additional information.
(3) Represents investing non-cash activity. See Note 4, "Variable Interest Entities," for additional information.

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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)	10,068,479,561	6,839,043,005	2,773,698,558				455,737,998
4	Property Under Capital Leases	36,004,311	4,909,233	26,971,965				4,123,113
5	Plant Purchased or Sold							
6	Completed Construction not Classified	2,430,904,693	1,386,809,449	1,004,927,101				39,168,143
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	12,535,388,565	8,230,761,687	3,805,597,624				499,029,254
9	Leased to Others							
10	Held for Future Use	4,561,212	4,492,410	45,793				23,009
11	Construction Work in Progress	765,644,494	418,536,930	307,224,755				39,882,809
12	Acquisition Adjustments	35,143,768	35,143,768					
13	Total Utility Plant (8 thru 12)	13,340,738,039	8,688,934,795	4,112,868,172				538,935,072
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	5,319,479,667	3,540,815,387	1,443,421,053				335,243,227
15	Net Utility Plant (13 less 14)	8,021,258,372	5,148,119,408	2,669,447,119				203,691,845
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	4,965,315,856	3,480,972,254	1,400,629,216				83,714,386
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	354,163,811	59,843,133	42,791,837				251,528,841
22	Total in Service (18 thru 21)	5,319,479,667	3,540,815,387	1,443,421,053				335,243,227
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)	5,319,479,667	3,540,815,387	1,443,421,053				335,243,227

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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: 04/17/2023	Year/Period of Report End of: 2022/ 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	77,966,830	1,737,187	(28,558)			79,732,575
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	77,968,219	1,737,187	(28,558)			79,733,964
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	5,145,662	501				5,146,163
9	(311) Structures and Improvements	483,495,712	3,483,159	215,300			486,763,571
10	(312) Boiler Plant Equipment	1,351,566,646	13,499,233	4,901,745	(13,045)		1,360,151,089
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	354,540,241	1,855,239	1,178,580			355,216,900
13	(315) Accessory Electric Equipment	204,916,855	236,319	24,852			205,128,322
14	(316) Misc. Power Plant Equipment	38,500,601	2,165,084	556,263			40,109,422
15	(317) Asset Retirement Costs for Steam Production	247,601,406	(1,057,720)	2,558,041	(85,562)		243,900,083
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,685,767,123	20,181,815	9,434,781	(98,607)		2,696,415,550
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						
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	10,224,133	432,829	644			10,656,318

29	(332) Reservoirs, Dams, and Waterways	45,905,556	9,610,888	97,538			55,418,906
30	(333) Water Wheels, Turbines, and Generators	13,333,053	384,232	(22,622)			13,739,907
31	(334) Accessory Electric Equipment	2,416,904		7			2,416,897
32	(335) Misc. Power Plant Equipment	772,508	193,113				965,621
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)	72,675,291	10,621,062	75,567			83,220,786
36	D. Other Production Plant						
37	(340) Land and Land Rights	1,034,100	(2,606)				1,031,494
38	(341) Structures and Improvements	13,970,472	928,299	61,757			14,837,014
39	(342) Fuel Holders, Products, and Accessories	11,820,034					11,820,034
40	(343) Prime Movers	107,449,738	6,124,166	473,044			113,100,860
41	(344) Generators	47,299,891	184,004				47,483,895
42	(345) Accessory Electric Equipment	51,926,276					51,926,276
43	(346) Misc. Power Plant Equipment	5,761,246	53,889				5,815,135
44	(347) Asset Retirement Costs for Other Production						
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	239,261,757	7,287,752	534,801			246,014,708
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,997,704,171	38,090,629	10,045,149	(98,607)		3,025,651,044
47	3. Transmission Plant						
48	(350) Land and Land Rights	88,488,978	(4,969,779)	11,738			83,507,461
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	75,707,161	(3,330,212)	5,377			72,371,572
50	(353) Station Equipment	899,272,083	60,449,147	12,777,378			946,943,852
51	(354) Towers and Fixtures	141,674,301	54,532,571	1,028,369	2,092,713		197,271,216
52	(355) Poles and Fixtures	484,549,785	57,860,637	2,080,791	(1,269,557)		539,060,074
53	(356) Overhead Conductors and Devices	290,597,288	24,033,413	1,244,165	(823,154)		312,563,382
54	(357) Underground Conduit	740,689					740,689
55	(358) Underground Conductors and Devices	3,172,675	6,676				3,179,351
56	(359) Roads and Trails	75,949	(1)				75,948
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,984,278,909	188,582,452	17,147,818	2		2,155,713,545
59	4. Distribution Plant						
60	(360) Land and Land Rights	4,607,258	13,088	5			4,620,341
61	(361) Structures and Improvements	14,259,785	349,185	36,110			14,572,860
62	(362) Station Equipment	468,391,383	31,013,796	3,713,230			495,691,949
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	569,622,855	53,136,649	5,388,799			617,370,705
65	(365) Overhead Conductors and Devices	328,284,427	38,568,267	952,924			365,899,770

66	(366) Underground Conduit	5,056,449	(142,894)	16,955			4,896,600
67	(367) Underground Conductors and Devices	498,298,376	52,555,669	1,859,644			548,994,401
68	(368) Line Transformers	320,043,988	23,505,346	2,733,952			340,815,382
69	(369) Services	283,853,065	19,433,340	387,964			302,898,441
70	(370) Meters	84,551,257	1,767,436	219,358			86,099,335
71	(371) Installations on Customer Premises	8,867,145	385,011	191,338			9,060,818
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	54,325,335	8,333,924	3,847,775			58,811,484
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,640,161,323	228,918,817	19,348,054			2,849,732,086
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)						
85	6. General Plant						
86	(389) Land and Land Rights	118,478	1				118,479
87	(390) Structures and Improvements	20,712,797	340,181				21,052,978
88	(391) Office Furniture and Equipment	22,982,748	916,638	1,616,357			22,283,029
89	(392) Transportation Equipment	2,123,337	135,674				2,259,011
90	(393) Stores Equipment	835,159	151,879	26,083			960,955
91	(394) Tools, Shop and Garage Equipment	23,869,801	1,781,017	335,706			25,315,112
92	(395) Laboratory Equipment	5,871,521	8,172	228,419			5,651,274
93	(396) Power Operated Equipment	5,138,156	110,663				5,248,819
94	(397) Communication Equipment	32,346,457	339,053	348,772			32,336,738
95	(398) Miscellaneous Equipment	3,202,509	1,538,069	35,922			4,704,656
96	SUBTOTAL (Enter Total of lines 86 thru 95)	117,200,963	5,321,347	2,591,259			119,931,051
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)	117,200,963	5,321,347	2,591,259			119,931,051
100	TOTAL (Accounts 101 and 106)	7,817,313,585	462,650,432	49,103,722	(98,605)		8,230,761,690
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)	7,817,313,585	462,650,432	49,103,722	(98,605)		8,230,761,690

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ Q4

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)
1						
2						
3						
4						
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41						
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44						
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46						
47	TOTAL					

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ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	[(a)] Electric Right of Way - Hiple to Tri-State 345 Kv	12/31/1999		1,258,601
3	[(b)] Electric Right of Way - Munster to Kreitzburg Sub	12/31/2001		505,420
4	[(c)] Electric Right of Way - Tri-State To Stebuen 138 Kv	12/31/1999		305,082
5	[(d)] Tr-State 49.44 Acres (Two Parcels)	07/17/1995		158,860
6	[(e)] Land - Green Acres Substation #47	01/01/1996		147,295
7	[(f)] Land - Gary Plat #107	01/01/1968		182,416
8	[(g)] Land - Merrillville/Griffith - Super Power Elec Trans R/W	01/01/1991		941,819
9	[(h)] Land - Entire Company - Hammond Future Generating Station Plat #103, 104 & 105	01/01/1962		423,702
10	[(i)] Land - East End Project	08/01/2002		247,283
11	[(j)] Other Land Rights			321,932
12	[(k)] Transmission only amounts from above included in Attachment O - see Footnote			
21	Other Property:			
22				
23				
24				
25				
26				
27				
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44				
45				
46				
47	TOTAL			4,492,410

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FOOTNOTE DATA

(a) Concept: ElectricPlantHeldForFutureUseDescription

Date Expected to be used = Indefinite

(b) Concept: ElectricPlantHeldForFutureUseDescription

Date Expected to be used = Indefinite

(c) Concept: ElectricPlantHeldForFutureUseDescription

Date Expected to be used = Indefinite

(d) Concept: ElectricPlantHeldForFutureUseDescription

Date Expected to be used = Indefinite

(e) Concept: ElectricPlantHeldForFutureUseDescription

Date Expected to be used = Indefinite

(f) Concept: ElectricPlantHeldForFutureUseDescription

Date Expected to be used = Indefinite

(g) Concept: ElectricPlantHeldForFutureUseDescription

Date Expected to be used = Indefinite

(h) Concept: ElectricPlantHeldForFutureUseDescription

Date Expected to be used = Indefinite

(i) Concept: ElectricPlantHeldForFutureUseDescription

Date Expected to be used = Indefinite

(j) Concept: ElectricPlantHeldForFutureUseDescription

Date originally Included = VariousDate Expected to be used = Indefinite

(k) Concept: ElectricPlantHeldForFutureUseDescription

Transmission amounts from Pg 214 included in Attachment O: Line 2 = 1,258,601, Line 3 = 505,420, LIne 4 = 305,082, Line 5 = 158,860, Line 6 = 147,295, Line 8 = 941,819 and Line 11 = 63,539.
Total = 3,380,616

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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	138kV Synchronous Condenser Replace	48,641,344
2	Generation Strategy - Circuit 13897	18,916,295
3	Pre-Eng-OSI EMS Software/Hardware	10,781,889
4	Oakdale Fl. Gate Rep'l	10,649,884
5	TDSIC- Creston Sub Xfmr & Swgr Upgr	10,105,789
6	TDSIC- Marktown Sub Rebuild	9,512,821
7	TDSIC- Hanover Sub Rebuild Xfmr Brk	7,368,308
8	Electric Control Center Modernizati	7,098,198
9	TDSIC- AMI IT Install	6,067,274
10	TDSIC- Cir 12-299 Lindbergh Rebuild	5,832,571
11	TDSIC- Cir 3465 to 69kV LP Jnc Tee	5,828,400
12	TDSIC-Maple Sub Repl #2 Tr & Cap B	5,718,446
13	Gen Strat - LNG Substation	4,871,297
14	TDSIC- CISC to SLC Comm Fiber Optic	4,857,681
15	TDSIC- Aetna Sub Replace 3-34kV Brk	4,654,308
16	TDSIC- Cir 12-159 N Webster Rebuild	4,643,563
17	PIE-NICTD Doubletrack Corridor-Mill	4,575,860
18	TDSIC- Cir 6980 Rebuild Angola LaG	4,485,023
19	SCGS Advanced Gas Path Upgrade	4,462,112
20	PIE-NICTD Doubletrack Corridor-Gary	4,392,291
21	TDSIC- Chicago Ave Sub Repl 138kV B	4,268,537
22	PIE-NICTD Doubletrack Corridor-Gary a	4,195,193
23	SC Flared 7FA Enhanced Comp.	4,167,290
24	TDSIC- Gibson Switchgear Upgrade	3,735,683
25	TDSIC- 2022 Pole Insepections/ Trea	3,429,939
26	TDSIC- Schererville Sub Upgrade	3,419,328
27	PIE-NICTD Doubletrack Corridor-Rout	3,330,660
28	TDSIC- RMSGS Sub Repl 2-345 Breaker	3,310,030
29	TDSIC- Cir 12-508 Rebuild Ainsworth	3,175,865
30	PIE-NICTD Doubletrack Corridor-Ogde	2,910,982
31	IT/OT Performance Data - Renewables	2,793,159
32	Norway Ind Cntl Sys Netwk Fiber Opt	2,737,235
33	TDSIC- SouthLake Switchgear Upgrade	2,517,930
34	TDSIC- Aetna Sub Lattice Tower Comm	2,512,759
35	TDSIC- Cir 12-563 Rebuild Johnson	2,430,912
36	TDSIC- Chic Av Mitch USSS Comm Fib	2,409,346
37	TDSIC- PRP DB Pole Inspec/ Treatmen	2,408,920
38	TDSIC- Northport 138 & 69kV Breaker	2,349,459
39	PIE-NICTD Doubletrack Corridor-Beve	2,162,765

40	PRELIM-Green Acres to Miss St	2,049,137
41	TDSIC- Crocker Sub Recloser & Inc L	2,011,001
42	TDSIC- Woodmar #1 Transf & Switchge	2,002,609
43	RMS -16A&B, Serv Wtr, Hydrog	1,950,218
44	Aylesworth Subdivision	1,916,731
45	345kV Synchronous Condenser	1,857,109
46	Newbury Sub Switch #200 Rep'l	1,853,140
47	TDSIC- Griffith #1 Transf & Switchg	1,731,417
48	TDSIC- CISC to Munster Comm Fiber O	1,660,754
49	TDSIC- E Winamac 69kV Breaker Upgr	1,630,256
50	Robert A Taft Middle School	1,595,843
51	TDSIC- Marktown Sub Land Purchase	1,564,460
52	Oakdale Head Gate & Stop Log	1,516,662
53	TDSIC- Cir 6982 Koscuisko Rebuild	1,470,827
54	Generation Strategy - Circuit 13897 a	1,446,175
55	PRELIM-NCS-Ckt 6923&6976-Entech	1,377,454
56	TDSIC- St John New Sub 138/69kV	1,348,720
57	TDSIC- Indiana Harbor Com Ugr Monop	1,334,824
58	TDSIC- Ainsworth Comm Upgr Monopole	1,320,774
59	TDSIC- Sheffield Sub Repl 4-138 Brk	1,285,361
60	TDSIC- SIE KJR Viper Recl Crwn Pt	1,281,642
61	TDSIC- Highland Comm Upgr Lat Twr	1,270,120
62	TDSIC- UCR BK Woodlnd Pk Cir 12-540	1,243,090
63	NICTD West Lake Conflict 232	1,212,497
64	TDSIC- Menges Ditch Sub Land	1,205,314
65	TDSIC- SIE KJR 12-854, 12-513 Viper	1,174,239
66	TDSIC- UCR RWM Cir 12-125 N Liberty	1,166,358
67	AMAZON SEEFRIED SUBSTATION	1,165,738
68	U12 Catalyst Layer 2 Rep'l	1,159,965
69	Oakdale Ind Ctrl Syts Ntwk Fiber Op	1,109,667
70	NICTD West Lake Conflict 167	1,076,732
71	TDSIC- Novak Rd #1 Transformer Repl	1,068,087
72	TDSIC- Cir 13832 16 to E Win Steel	1,057,509
73	77th Ave Bridg 69kv Relia Improvmt	1,043,509
74	Norway Floodgate Replacement Projec	1,000,855
75	Total Other Projects Less than $1 Million	126,648,790
43	Total	418,536,930

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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	3,343,565,030	3,343,565,030		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	240,925,258	240,925,258		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts	4,063,780	[(a)]4,063,780		
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):				
9.2	Other: Regulatory Assets	10,336,739	10,336,739		
9.3	Other: Asset Retirement Obligations	(11,910,003)	(11,910,003)		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	243,415,774	243,415,774		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(46,562,501)	(46,562,501)		
13	Cost of Removal	(21,572,793)	(21,572,793)		
14	Salvage (Credit)	1,626,238	1,626,238		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(66,509,056)	(66,509,056)		
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	(42,818,551)	(42,818,551)		
17.3	Unrecovered NBV of RMS Plant Regulatory Asset				
17.4	COR Associated with Uncrecovered RMS Regulatory Asset	3,319,057	3,319,057		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,480,972,254	3,480,972,254		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,479,234,784	1,479,234,784		
21	Nuclear Production				
22	Hydraulic Production-Conventional	13,813,281	13,813,281		
23	Hydraulic Production-Pumped Storage				
24	Other Production	137,267,949	137,267,949		
25	Transmission	656,918,080	656,918,080		
26	Distribution	1,129,640,320	1,129,640,320		

27	Regional Transmission and Market Operation				
28	General	64,097,840	64,097,840		
29	TOTAL (Enter Total of lines 20 thru 28)	3,480,972,254	3,480,972,254		

FOOTNOTE DATA

(a) Concept: OtherClearingAccounts
Mobile Fuel Expenses = $4,005,253Unit 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			17,800,521	1,088,771		18,889,292	
4	Tax Savings Allocation			1,067,383			1,067,383	
42	Total Cost of Account 123.1 $		Total	48,867,904	1,088,771		49,956,675	

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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)	28,039,767	61,903,572	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	4,150,620	6,908,319	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	57,134,859	64,355,497	T&D
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	36,677,376	41,312,622	Electric
8	Transmission Plant (Estimated)	8,626,994	9,717,264	Electric
9	Distribution Plant (Estimated)	5,656,721	6,371,611	Electric and Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[(a)]1,914,176	[(b)]2,156,088	Electric and Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	110,010,126	123,913,082	
13	Merchandise (Account 155)	9,828	8,694	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)	8,958,259	7,159,394	Electric and Gas
17				
18				
19				
20	TOTAL Materials and Supplies	151,168,600	199,893,061	

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesOther
Miscellaneous
(b) Concept: PlantMaterialsAndOperatingSuppliesOther
Miscellaneous

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Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year	504,609		582,708		662,412		734,843		785,549		3,270,121	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	79,704		79,704		72,431		50,706		50,706		333,251	
5	Returned by EPA	893										893	
6													
7													
8	Purchases/Transfers In:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	2,496										2,496	
19	Other:												
20	Allowances Used												
20.1	Excess Surrender to EPA	2										2	
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	582,708		662,412		734,843		785,549		836,255		3,601,767	
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 EPA												
38	Deduct: Returned by EPA												
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)		35										35
45	Gains												
46	Losses												

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Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year	12,022		27,034		40,060		52,238		52,238		183,592	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	14,637		13,026		12,178						39,841	
5	Returned by EPA	5,182										5,182	
6													
7													
8	Purchases/Transfers In:												
9	Fathom Energy	54	1,150,000									54	1,150,000
10													
11													
12													
13													
14													
15	Total	54	1,150,000									54	1,150,000
16													
17	Relinquished During Year:												
18	Charges to Account 509	4,828										4,828	
19	Other:												
20	Allowances Used												
20.1	Excess Surrender to EPA												
21	Cost of Sales/Transfers:												
22	Dynergy Marketing and Trade	32										32	
23													
24													
25													
26													
27													
28	Total	32										32	
29	Balance-End of Year	27,035	1,150,000	40,060		52,238		52,238		52,238		223,809	1,150,000
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												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ Q4

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 Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
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: 04/17/2023	Year/Period of Report End of: 2022/ 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: 04/17/2023	Year/Period of Report End of: 2022/ 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	J607238 - MISO	104,035	560/568	104,342	560/568
3	J607239 - MISO	48,881	560/568	49,058	560/568
4	J607240 - MISO	144,773	560/568	107,563	560/568
5	J607241 - MISO	95,848	560/568	138,270	560/568
6	J607242 - MISO	84,605	560/568	161,532	560/568
7	J607243 - MISO	47,292	560/568	48,391	560/568
8	J607244 - MISO	44,819	560/568	45,506	560/568
9	J607245 - MISO	47,549	560/568	47,586	560/568
10	J607246 - MISO	78,936	560/568	79,969	560/568
11	J607247 - MISO	44,988	560/568	45,535	560/568
12	J607248 - MISO	55,626	560/568	55,469	560/568
13	J607249 - MISO	71,265	560/568	72,176	560/568
14	J607250 - MISO	49,835	560/568	82,033	560/568
15	J607251 - MISO	25,085	560/568	57,461	560/568
16	J607252 - MISO	10,780	560/568	14,869	560/568
17	J607253 - MISO	162,370	560/568	114,168	560/568
18	J607254 - MISO	4,801	560/568	4,801	560/568
19	J607255 - MISO	4,801	560/568	4,801	560/568
20	Total	1,126,289		1,233,530	
21	**Generation Studies**				
39	Total				
40	Grand Total	1,126,289		1,233,530	

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS 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	2,101,835	5,032,897	403/408/421/431/880	6,667,943	466,789
3	TDSIC Gas Deferred 20 - Order 44403/45330/44988	12,969,332	3,108,317	403/408/421/431/880	2,788,296	13,289,353
4	Gas Rate Case Costs - Order 44988/45621	1,452,686	508,697	923	274,192	1,687,191
5	FMCA Rider Deferred 80 - Order 45007/45660	4,851,227	8,292,102	107/108/403	6,952,610	6,190,719
6	FMCA Rider Deferred 20 - Order 45007/45660	11,747,480	4,376,708	107/108	1,146,994	14,977,194
7	Demand Side Management - Order 44001	598,439		456	434,266	164,173
8	Underrecovered Gas Costs - Order 43629	20,889,935		805	18,007,621	2,882,314
9	Other Miscellaneous - Order 44988	(901,907)		923	1,000,716	(1,902,623)
10	ELECTRIC					
11	EERM O&M Deferral - Order 45159	6		548	6	
12	EERM Depreciation Deferral - Order 45159	(16)	16			
13	Electric Rate Case Costs - Order 44688/45159	1,905,418	1,371,251	923	580,821	2,695,848
14	Electric Vehicle Deferral - Order 44688	42,354		923	21,177	21,177
15	Sugar Creek - Order 44688	3,472,388		403/431	1,984,236	1,488,152
16	Sugar Creek Stub - Order 44688	894,842		403/431	511,344	383,498
17	FMCA Rider Deferred 80	170,039				170,039
18	FMCA Rider Deferred 20 - Order 44688	4,491,355		403/408/421/431/548	895,981	3,595,374
19	TDSIC Deferred - Order 45557	28,702,354	12,180,438	403/408/421/431	13,806,361	27,076,431
20	TDSIC Deferred 20 - Order 44688/44733	17,230,106	9,268,563	403/408/421/431	2,340,312	24,158,357
21	Mercury Air Toxins Deferred 20 - Order 44688	307,953		403/421/431/548	86,508	221,445
22	RA Rider Deferral - Order 44155	1,290,260		456	1,290,260	
23	CIS Rider 677 - Order 44688/45159	5,812,117		442	443,376	5,368,741
24	Fuel Surcharge Litigation - Order 38706-FAC-125	1,634,236	2,181,707			3,815,943
25	Rosewater Wind Joint Venture - Order 45194	5,369,263	449,767			5,819,030
26	Indiana Crossroads Wind Joint Venture - Order 45310	11,533,407	812,259			12,345,666
27	Dunns I Solar Joint Venture - Order 45462		149,493,294			149,493,294
28	Schahfer Generation - Order 45159	695,272,917		407	50,054,650	645,218,267
29	Renewable Projects Costs - Order 45194/45462/45524/45529/45511	3,934,851	1,177,286			5,112,137
30	Environmental Current	28,500		923	28,500	
31	Underrecovered Fuel Costs - Order 38706		24,734,851			24,734,851
32	Indiana Crossroads Solar Joint Venture - Order 45524		153,765,675			153,765,675

33	OTHER					
34	FAS 133 Current - Order 38706/43629	1,906,511	3,639,242			5,545,753
35	FAS 133 Non-Current - Order 38706/43629	7,711,560		175,232	3,259,230	4,452,330
36	FAS 158-OPEB - Order 45159/45621	62,494,381		228	39,596,637	22,897,744
37	FAS 158-Pension - Order 45159/45621	334,380,753	87,910,233			422,290,986
38	Federal Income Tax - Order 45159/45621	6,074,462				6,074,462
39	COVID Costs - Order 45377	5,105,084		144	112,448	4,992,636
44	TOTAL	1,253,474,128	468,303,303		152,284,485	1,569,492,946

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Goodwill	17,753,079				17,753,079
2	Materials Holding	4,258,664	8,152,712	107/506/588/880	7,298,545	5,112,831
3	Gas Hedging Gain/Loss	38,329	125			38,454
4	Pension Trust Asset	99,380,091		182/926	83,485,559	15,894,532
5	Wind Farm Development	76,476,013	730,149	182	1,245,753	75,960,409
6	Legal Accruals		540,779			540,779
47	Miscellaneous Work in Progress					
48	Deferred Regulatroy Comm. Expenses (See pages 350 - 351)					
49	TOTAL	197,906,176				115,300,084

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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		177,024,898	164,619,305
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	177,024,898	164,619,305
9	Gas		
10		165,301,445	175,971,419
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	165,301,445	175,971,419
17.1	Other (Specify)		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	342,326,343	340,590,724

Notes

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
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									
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2023-04-17	Year/Period of Report End of: 2022/ Q4

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.

a. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
b. 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.
c. 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.
d. 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	194,195,925
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	
16	Ending Balance Amount	194,195,925
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	206,741,159

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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: 04/17/2023	Year/Period of Report End of: 2022/ 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, Ot 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 associ 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 ac 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 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)	In
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	75,000,000	
13	Long Term Note, 6.525%		80,000,000					06/06/2008	06/06/2023	06/06/2008	06/06/2023	80,000,000	
14	Long Term Note, 6.410%		120,000,000					12/04/2009	12/04/2029	12/04/2009	12/04/2029	120,000,000	
15	Long Term Note, 4.530%		55,000,000					12/19/2012	12/21/2037	12/19/2012	12/21/2037	55,000,000	
16	Long Term Note, 4.830%		95,000,000					12/19/2012	12/19/2042	12/19/2012	12/19/2042	95,000,000	
17	Long Term Note, 5.170%		89,000,000					07/24/2013	07/26/2038	07/24/2013	07/26/2038	89,000,000	
18	Long Term Note, 5.430%		95,000,000					07/24/2013	07/24/2043	07/24/2013	07/24/2043	95,000,000	
19	Long Term Note, 4.990%		66,000,000					02/13/2014	02/15/2044	02/13/2014	02/15/2044	66,000,000	
20	Long Term Note, 4.350%		82,000,000					12/18/2014	12/16/2044	12/18/2014	12/16/2044	82,000,000	
21	Long Term Note, 4.55%		93,750,000					06/26/2015	06/06/2035	06/26/2015	06/06/2035	93,750,000	
22	Long Term Note, 4.99%		93,750,000					06/26/2015	06/26/2045	06/26/2015	06/26/2045	93,750,000	

23	Long Term Note, 4.7006%		91,000,000					12/30/2015	12/30/2045	12/30/2015	12/30/2045	91,000,000	
24	Long Term Note, 4.3640%		210,000,000					12/30/2016	12/30/2046	12/30/2016	12/30/2046	210,000,000	
25	Long Term Note, 4.1611%		40,000,000					06/30/2017	06/30/2047	06/30/2017	06/30/2047	40,000,000	
26	Long Term Note, 4.1123%		162,500,000					09/29/2017	09/29/2047	09/29/2017	09/29/2047	162,500,000	
27	Long Term Note. 4.530%		450,000,000					06/29/2018	06/29/2048	06/29/2018	06/29/2048	450,000,000	2
28	Long Term Note. 3.568%		150,000,000					09/30/2019	09/30/2019	09/30/2019	09/30/2049	150,000,000	
29	Long Term Note, 3.174%		208,000,000					06/30/2020	06/30/2050	06/30/2020	06/30/2050	208,000,000	
30	Long Term Note 3.272%		175,000,000					06/30/2021	06/30/2051	06/30/2021	06/30/2051	175,000,000	
31	Long Term Note 5.081%		225,000,000					06/30/2022	06/30/2052	06/30/2022	06/30/2052	225,000,000	
32	Long Term Note 5.650%		210,000,000					12/30/2022	12/30/2052	12/30/2022	12/30/2052	210,000,000	
33	Subtotal		2,866,000,000									2,866,000,000	11
34	Other Long Term Debt (Account 224)												
35	Medium Term Notes, Series E, Variable %		58,000,000					06/06/1997	08/04/2027	06/06/1997	08/04/2027	58,000,000	
36	Subtotal		58,000,000									58,000,000	
33	TOTAL		2,924,000,000									2,924,000,000	12

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ Q4

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

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	327,232,579
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	SFAS133 - Book Hedging Income/Loss	(60,430,891)
6	Federal Net Operating Loss Carryforward	(20,148,276)
7	Total	(80,579,167)
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal Current Income Tax Expense	35,701,832
11	Federal Deferred Income Tax Expense	18,802,735
12	State Current Income Tax Expense	7,933,287
13	State Deferred Income Tax Expense	6,164,870
14	Permanent Item Allocation - NCS	4,087
15	Parking	13,761
16	NCS Allocation - Parking	3,280
17	Business Meals & Entertainment	17,500
18	Fines & Penalties	405,241
19	Employee Stock Purchase Plan	284,487
20	NCS Allocation - Employee Stock Purchase Plan	46,133
21	Partnership K-1 Perm	12,790,417
22	AFUDC Equity	(13,005,190)
23	Pension Expense	82,761,594
24	SFAS 106/112 Retirement Benefit Expense	(4,577,676)
25	Environmental Remediation	(1,260,954)
26	Taxes Other Than Income Taxes	(2,072,148)
27	Lobbying Expenses	57,790
28	NCS Allocation: Lobbying Expenses	188,467
29	Accrued Liabilities	(6,365,041)
30	Other Accrued Liabilities	25,284,094
31	Bad Debt Expense	188,811
32	Expenses Accrued on Regulatory Assets	(73,649,858)
33	Expenses Accrued on Regulatory Liabilities	74,425,273
34	Post Employement Benefits	(47,259,789)
35	Total	116,883,003
14	Income Recorded on Books Not Included in Return	
15	Equity in Subs - NIPSCO Accounts Receivable Corp	13,949,716
16	Total	13,949,716

19	Deductions on Return Not Charged Against Book Income	
20	Property	179,966,820
21	Partnership K-1 Temp	12,670,452
22	Property Plant Equipment	37,314
23	PISCC Equity	(935,622)
24	Joint Ventures	(2,299,801)
25	NARC Sub Income Adj	(33,569)
26	Other	(2,794,265)
27	Total	186,611,329
27	Federal Tax Net Income	162,975,370
28	Show Computation of Tax:	
29	Federal Net Taxable Income @ 21.0%	34,224,828
30	Provision Normal - BTR & Reserve Study	1,477,004
31	Provision Normal - Renewables	43,639,434
32	Federal Income Taxes - Current Provision	79,341,266

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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 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 act
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 balancir 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 pr 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 colu 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 accou
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)	Electric (Accoun 408.1, 409.1) (l)
1	FICA/Medicare/Unemployment	Payroll Tax	Indiana	2022	9,688,268		23,804,277	31,433,806		2,058,739		7,731,8
2	Income	Income Tax	Indiana	2022	28,716,500		79,341,266	30,202,517		77,855,249		79,204,7
3	**Subtotal Federal Tax**				38,404,768		103,145,543	61,636,323		79,913,988		86,936,6
4	Utility Receipts	Other Taxes and Fees	Indiana	2022	2,999,315		20,275,424	23,592,715	679,004	361,028		11,811,3
5	Unemployment Compensation	Unemployment Tax	Indiana	2022	2,897		88,136	91,058	1	(24)		32,3
6	Corporate Net Income	Income Tax	Indiana	2022			15,780,233	(8,755)	[(a)](6,301,591)	9,487,397		10,420,4
7	Sales and Use	Sales And Use Tax	Indiana	2022	3,591,441		14,828,493	16,177,616	(758,770)	1,483,548		(1,070,39
8	Public Utility Fee	Other Taxes and Fees	Indiana	2022		2,379,632	2,770,211	12,397,629		(693,991)	11,313,059	1,847,3
9	**Subtotal State Tax**				6,593,653	2,379,632	53,742,497	52,250,263	(6,381,356)	10,637,958	11,313,059	23,041,1
10	Real Estate and Personal Property	Real Estate Tax	Indiana	2022	38,833,125		36,093,399	38,165,541		36,760,983		21,313,5
11		Severance Tax										
12	**Subtotal Local Tax**				38,833,125		36,093,399	38,165,541		36,760,983		21,313,5
40	TOTAL				83,831,546	2,379,632	192,981,439	152,052,127	(6,381,356)	127,312,929	11,313,059	131,291,3

FOOTNOTE DATA

(a) 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: 04/17/2023	Year/Period of Report End of: 2022/ 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%	32,680			E411.4	32,680			27.6	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	32,680				32,680				
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10	3%									
11	4%									
12	7%									
13	Gas Utility									
14	10	1,193,740			G422.4	316,008		877,732	34.4	`
47	OTHER TOTAL	1,193,740				316,008		877,732		
48	GRAND TOTAL	1,226,420				348,688		877,732		

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Investigation and cleanup	31,308,314	242/930	19,511,835	19,510,535	31,307,014
2	Deferred Revenue	380,572	555	2,548,916	2,388,555	220,211
3	Wind Farm Development	75,739,179				75,739,179
47	TOTAL	107,428,065		22,060,751	21,899,090	107,266,404

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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: 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	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: 04/17/2023	Year/Period of Report End of: 2022/ 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.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	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)	Balance at End of Year (k)
1	Account 282										
2	Electric	874,186,905	(31,134,453)	22,521,228		2,182,178	254/282	1,126,074	254/190	24,796,656	842,019,628
3	Gas	258,369,379	28,179,317	10,903,202			254/282	130,473	254/182/190	9,627,896	285,142,917
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	1,132,556,284	(2,955,136)	33,424,430		2,182,178		1,256,547		34,424,552	1,127,162,545
6	Other (Non-Utility)										
9	TOTAL Account 282 (Total of Lines 5 thru 8)	1,132,556,284	(2,955,136)	33,424,430		2,182,178		1,256,547		34,424,552	1,127,162,545
10	Classification of TOTAL										
11	Federal Income Tax	940,972,049	(8,583,979)	32,348,359		1,752,253		1,256,547		32,918,556	929,949,467
12	State Income Tax	191,584,235	5,628,843	1,076,071		429,925				1,505,996	197,213,078
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: 04/17/2023	Year/Period of Report End of: 2022/ 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)	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 283										
2	Electric										
3	Electric	87,567,125	32,370,770	31,066,231	1,562,978						90,434,642
9	TOTAL Electric (Total of lines 3 thru 8)	87,567,125	32,370,770	31,066,231	1,562,978						90,434,642
10	Gas										
11	Gas	35,256,031	29,925,444	25,822,103	618,303						39,977,675
17	TOTAL Gas (Total of lines 11 thru 16)	35,256,031	29,925,444	25,822,103	618,303						39,977,675
18	TOTAL Other										
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	122,823,156	62,296,214	56,888,334	2,181,281						130,412,317
20	Classification of TOTAL										
21	Federal Income Tax	99,773,845	50,428,407	46,641,601	1,751,532						105,312,183
22	State Income Tax	23,049,311	11,867,807	10,246,733	429,749						25,100,134
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: 04/17/2023	Year/Period of Report End of: 2022/ 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	1,183,506	142,426	210,070		973,436
3	Demand Side Management- Gas - Order 44001	594,221			934,580	1,528,801
4	Federal Income Tax - Gas - Order 45159/45621	116,508,106	409,411	9,497,425		107,010,681
5	ELECTRIC					
6	RTO Rider Deferral - Order 44156	3,863,454			2,155,933	6,019,387
7	Green Power - Order 44198	118,055			588,605	706,660
8	Overrecovered Fuel Costs - Order 38706	8,842	501,555	8,842		
9	Schahfer Revenue Credit - Order 45159	1,907,486			2,669,370	4,576,856
10	FMCA Rider Tracker 80	645				645
11	Demand Side Management - Elec - Order 43618	14,509,966			5,381,256	19,891,222
12	RA Rider Deferral - Order 44155				3,363,736	3,363,736
13	Federal Income Tax - Elec - Order 45159/45621	392,307,714	409,411	23,670,580		368,637,134
14	COMBINED					
15	FAS133 - Order 38706/43629	34,210,307			55,771,058	89,981,365
16	ITC Federal Income Tax - Order 45159/45621	1,246,021	255	177,479		1,068,542
41	TOTAL	566,458,323		33,564,396	70,864,538	603,758,465

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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	592,426,073	567,918,385	3,482,939	3,546,813	423,568	420,567
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	570,994,649	534,910,659	3,682,376	3,698,032	58,170	57,701
5	Large (or Ind.) (See Instr. 4)	560,956,222	494,331,038	7,915,344	8,253,705	2,136	2,146
6	(444) Public Street and Highway Lighting	8,006,644	8,236,507	40,607	43,459	280	280
7	(445) Other Sales to Public Authorities	2,474,576	2,438,419	16,794	18,026	431	437
8	(446) Sales to Railroads and Railways	1,631,044	1,775,169	12,518	17,655	1	1
9	(448) Interdepartmental Sales	2,947,241	4,061,281	19,564	29,318		
10	TOTAL Sales to Ultimate Consumers	1,739,436,449	1,613,671,458	15,170,142	15,607,008	484,586	481,132
11	(447) Sales for Resale	1,938,723	3,471,617	49,973	124,652	3	3
12	TOTAL Sales of Electricity	1,741,375,172	1,617,143,075	15,220,115	15,731,660	484,589	481,135
13	(Less) (449.1) Provision for Rate Refunds						
14	TOTAL Revenues Before Prov. for Refunds	1,741,375,172	1,617,143,075	15,220,115	15,731,660	484,589	481,135
15	Other Operating Revenues						
16	(450) Forfeited Discounts	5,891,886	5,404,228				
17	(451) Miscellaneous Service Revenues	[a]796,720	[c]1,046,549				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	4,135,422	2,284,363				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[b](11,333,289)	[d](15,118,874)				
22	(456.1) Revenues from Transmission of Electricity of Others	90,011,022	90,006,339				
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	89,501,761	83,622,605				

27	TOTAL Electric Operating Revenues	1,830,876,933	1,700,765,680				

Line12, column (b) includes $ 2,050,530 of unbilled revenues.
Line12, column (d) includes 33,912 MWH relating to unbilled revenues

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: MiscellaneousServiceRevenues

	2022
Reconnect Charges (451)	$ 384,742
Other Misc Services	$ 411,978
	$ 796,720

(b) Concept: OtherElectricRevenue

	2022
Other Tracker Deferrals	$(11,270,911)

(c) Concept: MiscellaneousServiceRevenues

	2021
Reconnect Charges (451)	$ 425,760
Other Misc Services	$ 620,789
	$ 1,046,549

(d) Concept: OtherElectricRevenue

	2021
Other Tracker Deferrals	$(15,118,874)

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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					
4					
5					
6					
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40					
41					
42					
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: 04/17/2023	Year/Period of Report End of: 2022/ 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 - 811 - Residential	3,475,043	590,749,868	423,552	8,205	0.1700
2	Res - 850 - Street Lighting	47	11,461	14	3,357	0.2439
3	Res - 855 - Traffic and Directive Lighting	3	809	2	1,500	0.2697
4	Res - 860 - Dusk to Dawn Area Lighting	7,846	1,663,935			0.2121
41	TOTAL Billed Residential Sales	3,482,939	592,426,073	423,568	8,223	0.1701
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	3,482,939	592,426,073	423,568	8,223	0.1701

SALES OF ELECTRICITY BY RATE SCHEDULES

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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 - 820 - Commercial and General Service - Heat Pump	9,738	1,022,631	173	56,289	0.1050
2	Com - 821 - General Service - Small	1,455,072	262,245,837	53,526	27,184	0.1802
3	Com - 822 - Commercial Spaceheating	8,001	994,688	174	45,983	0.1243
4	Com - 823 - General Service - Medium	777,394	122,168,173	2,807	276,948	0.1572
5	Com - 824 - General Service - Large	719,600	99,525,952	316	2,277,215	0.1383
6	Com - 826 - Off-Peak Service	689,321	81,302,895	177	3,894,469	0.1179
7	Com - 841 - Municipal Power	14,481	2,137,639	306	47,324	0.1476
8	Com - 842 - Intermittent Wastewater Pumping	343	118,307			0.3449
9	Com - 850 - Street Lighting	2,154	275,857	666	3,234	0.1281
10	Com - 855 - Traffic and Directive Lighting	318	47,203	25	12,720	0.1484
11	Com - 860 - Dusk to Dawn Area Lighting	5,954	1,107,765	0		0.1861
12	Com - 1750 - Electric Guaranteed Minimum		47,702	0		
41	TOTAL Billed Small or Commercial	3,682,376	570,994,649	58,170	63,304	0.1551
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)					
43	TOTAL Small or Commercial	3,682,376	570,994,649	58,170	63,304	0.1551

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	Ind - 821 - General Service - Small	158,394	27,373,397	1,514	104,620	0.1728
2	Ind - 823 - General Service - Medium	162,067	26,120,711	294	551,248	0.1612
3	Ind - 824 - General Service - Large	764,926	101,812,588	201	3,805,602	0.1331
4	Ind - 825 - Metal Melting Service	89,136	8,713,233	6	14,856,000	0.0978
5	Ind - 826 - Off-Peak Service	882,937	100,914,480	80	11,036,713	0.1143
6	Ind - 831 - Industrial Power Service - Large	5,429,948	259,684,199	7	775,706,857	0.0478
7	Ind - 832 - Industrial Power Service - Small	168,098	16,502,384	5	33,619,600	0.0982
8	Ind - 833 - Industrial Power Service - Small - HLF	259,398	24,191,775	4	64,849,500	0.0933
9	Ind - 841 - Municipal Power	215	33,743	5	43,000	0.1569
10	Ind - 842 - Intermittent Wastewater Pumping	5	1,567			0.3134
11	Ind - 850 - Street Lighting	23	3,203	17	1,353	0.1393
12	Ind - 860 - Dusk to Dawn Area Lighting	197	38,068			0.1932
13	Ind - 865 - Renewable Feed-In Tariff		(15,086)			
14	Ind - 877 - Economic Development Rider		(4,418,040)	3		
15	Ind - 1750 - Electric Guaranteed Minimum					
41	TOTAL Billed Large (or Ind.) Sales	7,915,344	560,956,222	2,136	3,705,685	0.0709
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)					
43	TOTAL Large (or Ind.)	7,915,344	560,956,222	2,136	3,705,685	0.0709

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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						
2						
3						
4						
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41	TOTAL Billed Commercial and Industrial Sales					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL					

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	PS&H - 850 - Street Lighting	34,039	6,944,998	167	203,826	0.2040
2	PS&H - 855 - Traffic and Directive Lighting	6,368	1,029,036	113	56,354	0.1616
3	PS&H - 860 - Dusk to Dawn Area Lighting	200	32,610			0.1631
41	TOTAL Billed Public Street and Highway Lighting	40,607	8,006,644	280	145,025	0.1972
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	40,607	8,006,644	280	145,025	0.1972

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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 - 823 - General Service - Medium	775	142,785	2	387,500	0.1842
2	PA - 841 - Municipal Power	15,991	2,327,431	428	37,362	0.1455
3	PA - 850 - Street Lighting	9	720	1	9,000	0.0800
4	PA - 860 - Dusk to Dawn Area Lighting	19	3,640			0.1916
41	TOTAL Billed Other Sales to Public Authorities	16,794	2,474,576	431	38,965	0.1473
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	16,794	2,474,576	431	38,965	0.1473

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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	R&R - 844 - Railroad Power Service	12,518	1,631,044	1	12,518,000	0.1303
41	TOTAL Billed Sales To Railroads and Railways	12,518	1,631,044	1	12,518,000	0.1303
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	12,518	1,631,044	1	12,518,000	0.1303

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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	Interdepartmental Sales	19,564	2,947,241	0		0.1506
41	TOTAL Billed Interdepartmental Sales	19,564	2,947,241			0.1506
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	19,564	2,947,241			0.1506

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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	15,170,142	1,739,436,449	484,586	31,305	0.1147
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts					
43	TOTAL - All Accounts	15,170,142	1,739,436,449	484,586	31,305	0.1147

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

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

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

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

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

   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	Midwest ISO	OS	2				49,973		1,938,723		1,938,723
15	Subtotal - RQ										
16	Subtotal-Non-RQ						49,973		1,938,723		1,938,723
17	Total						49,973		1,938,723		1,938,723

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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	6,349,969	8,648,046
5	(501) Fuel	138,462,173	158,440,566
6	(502) Steam Expenses	25,461,868	34,967,510
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	5,437,834	6,796,319
10	(506) Miscellaneous Steam Power Expenses	4,705,689	11,583,891
11	(507) Rents		
12	(509) Allowances	770,000	
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	181,187,533	220,436,332
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,431,477	4,388,733
16	(511) Maintenance of Structures	13,555,326	13,780,886
17	(512) Maintenance of Boiler Plant	17,547,433	25,247,023
18	(513) Maintenance of Electric Plant	7,653,052	9,988,661
19	(514) Maintenance of Miscellaneous Steam Plant	17,329,908	13,857,233
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	59,517,196	67,262,536
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	240,704,729	287,698,868
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		

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	213,026	168,827
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	42,508	63,904
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	255,534	232,731
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	200,934	162,122
54	(542) Maintenance of Structures	3,286,052	2,365,082
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,586,586	1,654,779
56	(544) Maintenance of Electric Plant	1,083,359	1,252,175
57	(545) Maintenance of Miscellaneous Hydraulic Plant	12,926	13,305
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,169,857	5,447,463
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	6,425,391	5,680,194
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel	145,662,693	80,903,811
64	(548) Generation Expenses	752,824	754,959
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	146,415,517	81,658,770
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	145,975	495,485
71	(553) Maintenance of Generating and Electric Plant	4,011,476	3,345,674
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,307,620	1,140,767
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	6,465,071	4,981,926
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	152,880,588	86,640,696
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	327,008,013	202,901,328
76.1	(555.1) Power Purchased for Storage Operations	0	
77	(556) System Control and Load Dispatching	407,474	368,410
78	(557) Other Expenses	2,742,688	2,716,103
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	330,158,175	205,985,841
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	730,168,883	586,005,599

81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,880,108	1,884,108
85	(561.1) Load Dispatch-Reliability	[a]2,523,232	[c]2,820,277
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	[b]1,686,792	[d]1,734,039
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,879,049	61,125
88	(561.4) Scheduling, System Control and Dispatch Services	170,198	171,608
89	(561.5) Reliability, Planning and Standards Development	726,290	682,206
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	29,619,231	31,104,620
93	(562) Station Expenses	1,402,953	957,526
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	278,363	251,987
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	1,610,949	366,878
98	(567) Rents		
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	41,777,165	40,034,374
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,686,514	1,561,668
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	193,291	235,832
104	(569.2) Maintenance of Computer Software	563,670	582,106
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	5,409,059	6,669,796
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	5,567,361	3,996,171
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	45,710	46,700
111	TOTAL Maintenance (Total of Lines 101 thru 110)	13,465,605	13,092,273
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	55,242,770	53,126,647
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	5,331,215	5,604,858
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	5,331,215	5,604,858
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)	5,331,215	5,604,858
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	3,042,745	4,212,325
135	(581) Load Dispatching		
136	(582) Station Expenses	942,168	722,162
137	(583) Overhead Line Expenses	(1,264,672)	(768,468)
138	(584) Underground Line Expenses	3,490,481	2,881,683
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	8,640	20,458
140	(586) Meter Expenses	2,145,156	1,450,761
141	(587) Customer Installations Expenses	3,034,952	2,994,944
142	(588) Miscellaneous Expenses	4,562,125	5,427,741
143	(589) Rents		
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	15,961,595	16,941,606
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,213,746	1,994,763
147	(591) Maintenance of Structures	59,677	54,963
148	(592) Maintenance of Station Equipment	2,923,699	2,529,528
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	41,036,495	38,069,848
150	(594) Maintenance of Underground Lines	1,860,064	1,866,695
151	(595) Maintenance of Line Transformers	(71,545)	21,281
152	(596) Maintenance of Street Lighting and Signal Systems	361,765	371,568
153	(597) Maintenance of Meters	687,838	629,689
154	(598) Maintenance of Miscellaneous Distribution Plant	405,892	319,458
155	TOTAL Maintenance (Total of Lines 146 thru 154)	49,477,631	45,857,793
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	65,439,226	62,799,399
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,250,901	1,276,379
160	(902) Meter Reading Expenses	1,228,304	1,109,447
161	(903) Customer Records and Collection Expenses	8,428,805	8,481,043
162	(904) Uncollectible Accounts	6,740,458	5,168,607
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	17,648,468	16,035,476
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses		2,756

169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	479,493	446,811
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	479,493	449,567
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	578	
176	(913) Advertising Expenses	850,251	714,027
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	850,829	714,027
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	67,551,410	70,407,536
182	(921) Office Supplies and Expenses	22,964,725	21,929,761
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	49,303,495	41,809,953
185	(924) Property Insurance	3,364,333	3,375,295
186	(925) Injuries and Damages	13,889,277	14,366,143
187	(926) Employee Pensions and Benefits	20,182,822	13,029,498
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	1,454,293	1,421,446
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	118,671	133,642
192	(930.2) Miscellaneous General Expenses	691,838	2,012,148
193	(931) Rents	5,770,032	5,855,924
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	185,290,896	174,341,346
195	Maintenance		
196	(935) Maintenance of General Plant	11,048,844	10,925,494
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	196,339,740	185,266,840
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,071,500,624	910,002,413

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: LoadDispatchReliability
Balance Authority portion = 556,315
(b) Concept: LoadDispatchMonitorAndOperateTransmissionSystem
Balance Authority portion = 668,734
(c) Concept: LoadDispatchReliability
Balance Authority portion = 562,522
(d) Concept: LoadDispatchMonitorAndOperateTransmissionSystem
Balance Authority portion = 682,334

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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 c 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 unc 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 serv 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 buy 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 mat 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 contrac 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 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 (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 a 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 render 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 repor 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) t 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)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER			
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Tota (k+l+m Settlem ($) (n)
1	Barton Wind Farm	OS	none				118,894					7,201,385		7,201
2	Buffalo Ridge Wind Farm	OS	none				91,696					4,598,549		4,598
3	Greenfield Mills	OS	none				332					1,591		1
4	Midwest ISO	OS	none				6,600,519					250,260,935		250,260
5	Biotown	OS	none				36,842					4,645,214		4,645
6	Renewable Feed-In Tariff	OS	Rate 865				70,644					12,502,697		12,502
7	Co-Gen Capacity Purchases	OS	Rate 878				39,527					2,500,632		2,500
8	Jordan Creek	OS	none				1,362,374					43,418,856		43,418
9	Rosewater Wind JV	OS	none				335,291					6,895,168		6,895

10	Indiana Crossroads Wind JV	OS	none				842,899							
15	TOTAL						9,499,018					332,025,027		332,025

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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 c 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 cc 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 fo 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 Netw 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 Transm 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 servic 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
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 identificatio 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
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 a 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 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 renderec 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 colu 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 re
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 TRANSMISSI ELECTRICITY FOR OTHER: Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)
1	[(a)] Indiana Municpal Power Agency	Various	Indiana Municpal Power Agency	OS		Various	Various		397,401	397,401	498,415		
2	Wabash Valley Power Association	Various	Wabash Valley Power Association	FNO	NIPSCO Electric Rate Schedule 14	Various	Various	3,248	1,815,830	1,815,830	11,032,619		
3	Wabash Valley Power Association	Various	Wabash Valley Power Association	OS	NIPSCO Electric Rate Schedule 14	Various	Various				831,077		
4	Midcontinent Independent Systems Operator (Sched 7 & 8)	Various	Various	OS		Various	Various						2,773,485
5	Midcontinent Independent Systems Operator (Sched 1 & 2)	Various	Various	OS		Various	Various						389,349
6	Midcontinent Independent Systems Operator (Sched 9)	Various	Various	FNO		Various	Various						2,922,513
7	Midcontinent Independent Systems Operator (Sched 26, 37 & 38)	Various	Various	OS		Various	Various						2,291,690
8	Midcontinent Independent Systems Operator (Sched 26a)	Various	Various	OS		Various	Various						62,661,850

9	Midcontinent Independent Systems Operator (Sched 26a adjs)	Various	Various	AD		Various	Various						4,630,159
10	Midcontinent Independent Systems Operator (Sched 26c)	Various	Various	OS		Various	Various						2,813,817
11	Midcontinent Independent Systems Operator (Sched 26c adjs)	Various	Various	AD		Various	Various						(214,815)
12	Midcontinent Independent System Operator (Sched 26e)	Various	Various	OS		Various	Various						306,111
13	Midcontinent Independent System Operator (Sched 26e adjs)	Various	Various	AD		Various	Various						12,374
14	Midcontinent Independent System Operator (Sched 50)	Various	Various	OS		Various	Various						62,378
35	TOTAL							3,248	2,213,231	2,213,231	12,362,111		78,648,911

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ Q4

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: 04/17/2023	Year/Period of Report End of: 2022/ 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					
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49					
40	TOTAL				

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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: MegaWatt Hours Received (c)	TRANSFER OF ENERGY: MegaWatt Hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: 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: 04/17/2023	Year/Period of Report End of: 2022/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	303,766
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Other Operations Fees	187,723
7	Mischellaneous	200,349
46	TOTAL	691,838

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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			8,758,485		8,758,485
2	Steam Production Plant	92,018,728				92,018,728
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	3,228,783				3,228,783
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	19,433,690				19,433,690
7	Transmission Plant	51,132,606				51,132,606
8	Distribution Plant	82,535,517				82,535,517
9	Regional Transmission and Market Operation					
10	General Plant	1,956,842		19,473		1,976,315
11	Common Plant-Electric	2,516,369		13,750,269		16,266,638
12	TOTAL	252,822,535		22,528,227		275,350,762

B. Basis for Amortization Charges

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	469.089			3.07%		
14	311 Sugar Creek	7.773			3.07%		
15	Account 311 Total	476.862					
16	312 Generating Stations	1,262.59			4.41%		
17	312 Sugar Creek	89.944			3.77%		
18	Account 312 Total	1,352.534					
19	314 Generating Stations	299.394			3.14%		
20	314 Sugar Creek	55.806			3.14%		
21	Account 314 Total	355.2					

22	315 Generating Stations	200.378			2.49%		
23	315 Sugar Creek	4.712			2.49%		
24	Account 315 Total	205.09					
25	316 Generating Stations	35.215			3.49%		
26	316 Sugar Creek	3.429			3.49%		
27	Account 316 Total	38.644					
28	331 Hydro	10.656			5.14%		
29	332 Hydro	55.428			4.32%		
30	333 Hydro	13.26			2.62%		
31	334 Hydro	2.417			3.88%		
32	335 Hydro	0.966			4.61%		
33	Hydro Total	82.727					
34	341 Other	2.232			2.05%		
35	341 Sugar Creek	12.4			2.05%		
36	Account 341 Total	14.632					
37	342 Other	8.742			1.24%		
38	342 Sugar Creek	3.078			1.24%		
39	Account 342 Total	11.82					
40	343 Other	33.769			13.87%		
41	343 Sugar Creek	73.681			13.87%		
42	Account 343 Total	107.45					
43	344 Other	8.564			5.35%		
44	344 Sugar Creek	38.92			5.52%		
45	Account 344 Total	47.484					
46	345 Other	18.703			2.47%		
47	345 Sugar Creek	33.223			2.45%		
48	Account 345 Total	51.926					
49	346 Other	0.509			3.63%		
50	346 Sugar Creek	5.306			3.63%		

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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 (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 #44688, 2016 Electric Rate Case				538,459					923	307,769	230,690
3	Cause #45159, 2018 Electric Rate Case				1,366,958					923	276,015	1,090,943
4	Cause #44988, 2018 Gas Rate Case				626,666					923	167,112	459,554
5	Cause #45621, 2021 Gas Rate Case				826,021				508,697	923	107,080	1,227,638
6	Cause #45772, 2022 Electric Rate Case								1,374,215			1,374,215
7	Midcontinent Independent System Oper (MISO)											
8	Schedule 10 Fees		1,454,289	1,454,289			928	1,454,289				
46	TOTAL		1,454,289	1,454,289	3,358,104			1,454,289	1,882,912		857,976	4,383,040

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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:
   - A. Electric R, D and D Performed Internally:
     1. Generation
        - a. hydroelectric
          - i. Recreation fish and wildlife
          - ii. Other hydroelectric
        - b. Fossil-fuel steam
        - c. Internal combustion or gas turbine
        - d. Nuclear
        - e. Unconventional generation
        - f. Siting and heat rejection
     2. Transmission
        - a. Overhead
        - b. Underground
     3. Distribution
     4. Regional Transmission and Market Operation
     5. Environment (other than equipment)
     6. Other (Classify and include items in excess of $50,000.)
     7. Total Cost Incurred
   - B. Electric, R, D and D Performed Externally:
     1. Research Support to the electrical Research Council or the Electric Power Research Institute
     2. Research Support to Edison Electric Institute
     3. Research Support to Nuclear Power Groups
     4. Research Support to Others (Classify)
     5. Total Cost Incurred
3. Include in column (c) all R, D 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		20,188	921	20,188	
2	B (1)	Research support to Electric Power Research Institute (a)		375,482	921	375,482	
3	B (1)	Research support to Electric Power Research Institute (b)		122,783	923	122,783	
4	B (1)	Research support to Electric Power Research Institute (c)		35,000	930	35,000	
5	B (4)	Research support to Indiana Energy Association		644,234	921	644,234	
6	B (4)	Research support to North American Electric Reliability Group		693,994	921	693,994	
7	Total			1,891,681		1,891,681	

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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	17,291,925		
4	Transmission	6,162,195		
5	Regional Market			
6	Distribution	7,397,404		
7	Customer Accounts	6,411,238		
8	Customer Service and Informational	143,364		
9	Sales			
10	Administrative and General	21,562,812		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	58,968,938		
12	Maintenance			
13	Production	16,887,501		
14	Transmission	4,723,317		
15	Regional Market			
16	Distribution	14,905,239		
17	Administrative and General	187,143		
18	TOTAL Maintenance (Total of lines 13 thru 17)	36,703,200		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	34,179,426		
21	Transmission (Enter Total of lines 4 and 14)	10,885,512		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	22,302,643		
24	Customer Accounts (Transcribe from line 7)	6,411,238		
25	Customer Service and Informational (Transcribe from line 8)	143,364		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	21,749,955		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	95,672,138	30,118,614	125,790,752
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	2,309,177		
35	Transmission	3,115,819		
36	Distribution	8,645,255		
37	Customer Accounts	10,647,438		
38	Customer Service and Informational	252,512		

39	Sales			
40	Administrative and General	10,810,046		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	35,780,247		
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	557,194		
47	Transmission	1,852,588		
48	Distribution	9,970,984		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	12,380,766		
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	2,866,371		
56	Transmission (Lines 35 and 47)	4,968,407		
57	Distribution (Lines 36 and 48)	18,616,239		
58	Customer Accounts (Line 37)	10,647,438		
59	Customer Service and Informational (Line 38)	252,512		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	10,810,046		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	48,161,013	20,596,312	68,757,325
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	143,833,151	50,714,926	194,548,077
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	48,695,109	19,960,327	68,655,436
69	Gas Plant	26,792,861	13,424,177	40,217,038
70	Other (provide details in footnote):	5,120,265	87,249	5,207,514
71	TOTAL Construction (Total of lines 68 thru 70)	80,608,235	33,471,753	114,079,988
72	Plant Removal (By Utility Departments)			
73	Electric Plant	6,285,565	2,528,836	8,814,401
74	Gas Plant	5,576,668	2,511,830	8,088,498
75	Other (provide details in footnote):		1,209	1,209
76	TOTAL Plant Removal (Total of lines 73 thru 75)	11,862,233	5,041,875	16,904,108
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts:			
79	A/R from Associated Companies	1,501	32,654	34,155
80	Fuel Stock Expenses - Undistributed	6,057,889	1,295,043	7,352,932
81	Stores Expenses - Undistrubuted	5,576,493	(5,571,410)	5,083
82	Other Regulatory Assets	464,993	78,733	543,726

83	Preliminary Survey & Investigation Charges	(23,412)	(23,670)	(47,082)
84	Clearing Accounts	62,861,975	(62,341,766)	520,209
85	Misc Deferred Debits	8,090	4,348	12,438
86	A/P to Associated Companies	(18,385)	(87,497)	(105,882)
87	Misc Current & Accrued Liabilities	20,861,839	(23,099,322)	(2,237,483)
88	Other Deferred Credits	184	65	249
89	Other Regulatory Liabilities	279,412	42,043	321,455
90	Donations	365	24,937	25,302
91				
92				
93				
94				
95	TOTAL Other Accounts	96,070,944	(89,645,842)	6,425,102
96	TOTAL SALARIES AND WAGES	332,374,563	(417,288)	331,957,275

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ Q4

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	300,593,478	22,075,215	(1,922,256)			320,746,437
360-Land Rights	—					—
389-Land & Land Rights	8,464,359					8,464,359
390-Structures & Improvements	112,074,589	1,358,447	(127,298)			113,305,738
391-Office Furniture & Equipment	20,323,724	40,016	(6,957,906)			13,405,834
392-Transportation Equipment	843,945					843,945
393-Stores Equipment	2,530,710	35,973	(8,785)			2,557,898
394-Tool/Shop/Garage Equipment	7,770,282	897,093	(257,298)			8,410,077
395-Laboratory Equipment	1,608,110	309,187	(567)			1,916,730
396-Power Operated Equipment	4,168,305	1,300,708				5,469,013
397-Communication Equipment	23,156,134	705,384	(7,626,227)			16,235,291
398-Miscellaneous Equipment	2,924,328	205,600	(78,522)			3,051,406
Total Account 101 & 106	484,584,827	26,927,623	(16,978,859)	—	—	494,533,591
Account 101 & 106-Common Utility						
Plant Held for Future Use	23,009					23,009
Account 202.1 Right of Use	4,820,709			(749,596)		4,071,113
Total Common Utility Plant	489,428,545	26,927,623	(16,978,859)	(749,596)	—	498,627,713
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						69,851,161
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						388,482,439
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
Electr	68.38 %	265,659,283	36.20 %	25,284,246	66.02 %	26,600,700	317,544,229
Gas	31.62 %	122,823,156	63.80 %	44,566,915	33.98 %	13,693,413	181,083,484
Total	100.00 %	388,482,439	100.00 %	69,851,161	100.00 %	40,294,113	498,627,713

(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	102,493,588		
Depr Provision for year charge to (403) Depr Expense	3,663,292	2,505,100	1,158,192
Transportation Expenses - Clearing	0		
Other Accounts: Transfers between Pl. Accts	0		
Total Depr. Prov. for Year	3,663,292		
Net Charges for Plant Retired:			
Book Cost of Plant Retired	15,056,604		
Cost of Removal	70,945		
Salvage (Credit)	(239,727)		
Total Net Charges for Plant Ret.	14,887,822		
Other Credit Transfer btw reserve	0		
Retirement Work in Progress	202,962		
Balance End of Year	91,066,096	62,274,511	28,791,585
Allocation Basis: Ratio H		68.38 %	31.62 %

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

	Common Plant in Service	Allocated to Electric	Allocated to Gas
Balance Beginning of Year	226,806,336		
Amortization Provisions for year, charge to (404) Amortization Expense	24,722,505	16,906,203	7,816,302
Other Accounts:	0		
Total Amortization Provision for Year	24,722,505		
Other Debit: Adj netted prepaid	0		
Balance End of Year	251,528,841		
Allocation Basis: Ratio H	150,182,117	102,700,327	47,481,790
		68.38 %	31.62 %
Allocation Basis: Ration G-2	69,783,002	25,259,574	44,523,428
		36.20 %	63.80 %
Allocation Basis: Ratio MS	31,563,722	20,837,215	10,726,507
		66.02 %	33.98 %
Balance End of Year	251,528,841	148,797,116	102,731,725

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	71,252,440	184,816,312	359,324,021	420,889,760
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(6,318,164)	(19,417,357)	(27,484,031)	(35,167,705)
4	Transmission Rights	(1,980,109)	(3,560,686)	(1,936,524)	(195,302)
5	Ancillary Services	367,102	981,087	1,173,008	1,179,508
6	Other Items (list separately)				
7	Revenue Sufficiency Guarantee	168,865	606,759	840,860	(841,449)
8	Distribution of Losses	(2,376,942)	(6,003,864)	(12,417,392)	(14,695,815)
9	Inadvertent Energy	(25,827)	38,349	103,719	246,128
10	Resource Adequacy	286,686	981,382	8,153,527	13,939,370
46	TOTAL	61,374,051	158,441,982	327,757,188	385,354,495

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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	1,419			190,804
2	Reactive Supply and Voltage	5	MW	14,745			362,854
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other	5	MW	2,117			
8	Total (Lines 1 thru 7)	15		18,281	0		553,658

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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: 0									
1	January	2,589	7	9	2,231	304				54
2	February	2,543	25	9	2,213	277				53
3	March	2,273	7	11	1,952	273				48
4	Total for Quarter 1				6,396	854	0	0	0	155
5	April	2,432	18	11	2,122	259				51
6	May	3,015	31	12	2,596	356				63
7	June	3,346	21	15	2,817	459				70
8	Total for Quarter 2				7,535	1,074	0	0	0	184
9	July	3,240	5	16	2,745	427				68
10	August	3,426	3	13	2,924	430				72
11	September	2,931	1	16	2,483	386				62
12	Total for Quarter 3				8,152	1,243	0	0	0	202
13	October	2,237	19	8	1,938	252				47
14	November	2,284	18	11	1,963	273				48
15	December	2,483	23	17	2,083	348				52
16	Total for Quarter 4				5,984	873	0	0	0	147
17	Total				28,067	4,044	0	0	0	688

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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: 0									
1	January	2,589	7	9				2,589		2,589
2	February	2,543	25	9				2,543		2,543
3	March	2,273	7	11				2,273		2,273
4	Total for Quarter 1				0	0	0	7,405	0	7,405
5	April	2,432	18	11				2,432		2,432
6	May	3,015	31	12				3,015		3,015
7	June	3,346	21	15				3,346		3,346
8	Total for Quarter 2				0	0	0	8,793	0	8,793
9	July	3,240	5	16				3,240		3,240
10	August	3,426	3	13				3,426		3,426
11	September	2,931	1	16				2,931		2,931
12	Total for Quarter 3				0	0	0	9,597	0	9,597
13	October	2,237	19	8				2,237		2,237
14	November	2,284	18	11				2,284		2,284
15	December	2,483	23	17				2,483		2,483
16	Total for Quarter 4				0	0	0	7,004	0	7,004
17	Total Year to Date/Year				0	0	0	32,799	0	32,799

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2023-04-17	Year/Period of Report End of: 2022/ 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)	15,170,142
3	Steam	4,715,266	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	49,973
5	Hydro-Conventional	44,286	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other	2,232,740	27	Total Energy Losses	1,271,195
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	6,992,292	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	16,491,310
10	Purchases (other than for Energy Storage)	9,499,018			
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	2,213,231			
17	Delivered	2,213,231			
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)	16,491,310			

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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: 0					
29	January	1,427,904		2,319	5	18
30	February	1,285,139		2,316	25	9
31	March	1,310,219		2,048	28	9
32	April	1,280,708		2,238	18	11
33	May	1,328,079		2,655	31	12
34	June	1,402,047		2,900	21	15
35	July	1,531,765		2,824	5	16
36	August	1,537,889		2,980	3	13
37	September	1,339,446		2,583	1	16
38	October	1,187,851		1,991	19	8
39	November	1,156,519		1,999	18	11
40	December	1,308,741		2,144	23	17
41	Total	16,096,307	0			

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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 Mct.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
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	Combustion Turbine	Steam	Combine 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)	452	0	670	0	0
7	Plant Hours Connected to Load	4,200	348	10,854	21,040	0
8	Net Continuous Plant Capability (Megawatts)	455	155	2,105	316	237
9	When Not Limited by Condenser Water	0	0	0	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	1,415,876,000	18,917,000	2,124,170,000	2,213,823,000	1,175,220,000
13	Cost of Plant: Land and Land Rights	596,635	0	3,233,956	995,262	0
14	Structures and Improvements	141,327,237	2,226,647	337,034,719	12,605,483	7,773,414
15	Equipment Costs	717,409,364	74,637,125	1,088,718,890	154,209,001	153,182,599
16	Asset Retirement Costs	0	0	0	0	0
17	Total cost (total 13 thru 20)	859,333,236	76,863,772	1,428,987,565	167,809,746	160,956,013
18	Cost per KW of Installed Capacity (line 17/5) Including	1,591.3578	297.9216	1,687.1164	270.6609	0.0000
19	Production Expenses: Oper, Supv, & Engr	1,331,614	0	4,306,469	0	199,662
20	Fuel	48,197,759	2,532,285	105,117,845	94,957,700	50,408,812
21	Coolants and Water (Nuclear Plants Only)	0	0	0	0	0
22	Steam Expenses	5,476,704	0	19,604,625	0	51,987
23	Steam From Other Sources	0	0	0	0	0
24	Steam Transferred (Cr)	0	0	0	0	0
25	Electric Expenses	1,411,205	0	3,181,738	752,824	705,400
26	Misc Steam (or Nuclear) Power Expenses	2,777,467	0	2,529,129	0	152,764
27	Rents	0	0	0	0	0
28	Allowances	0	0	0	0	0

29	Maintenance Supervision and Engineering	871,727	0	2,271,000	0	288,751
30	Maintenance of Structures	4,851,694	0	8,457,630	145,975	28,749
31	Maintenance of Boiler (or reactor) Plant	7,316,614	0	9,386,617	0	803,331
32	Maintenance of Electric Plant	1,080,694	1,998,170	4,625,007	2,002,146	2,068,536
33	Maintenance of Misc Steam (or Nuclear) Plant	5,639,302	0	11,062,028	2,307,620	520,769
34	Total Production Expenses	78,954,780	4,530,455	170,542,088	100,166,265	55,228,761
35	Expenses per Net kWh	0.0558	0.2395	0.0803	0.0452	0.0470

35	**Plant Name**	Michigan City (Steam)	Michigan City (Steam)	RM Schahfer (Combustion Turbine)	RM Schahfer (Steam)	RM Schahfer (Steam)	Sugar Creek (Combine Cycle)	Sugar Creek (Steam)
36	Fuel Kind	Coal	Gas	Gas	Coal	Gas	Gas	Gas
37	Fuel Unit	T	Mcf	Mcf	T	Mcf	Mcf	Mcf
38	Quantity (Units) of Fuel Burned	825,233	168	364	1,137,851	500	22,716	
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9,438	1,046	1,044	11,041	1,045	1,062	
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	10,687		16,016	11,535		7,115	

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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 (total 13 thru 20)	
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	

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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 (total 13 thru 20)	
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

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GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, 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	5.1	25,015,000	37,573,418	4,084,067				hydro		
2	Norway	1923	7.20	9.0	19,270,000	45,621,581	6,336,331				hydro		

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ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provide
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), 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 (m), 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 affiliate fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compress 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)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)	Power Purchased for Storage Operations (555.1) (Dollars) (m)
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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: 04/17/2023	Year/Period of Report End of: 2022/ 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 lin 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 p
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 tran 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 distingu
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; conve 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 s 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 w line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
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 Le transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succin particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the responde whether 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 asso
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)		
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
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	15.92		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									1,594,387	333,069,869	334,664,25
216	138KV									11,596,685	252,277,810	263,874,49
217	345KV									43,869,666	409,250,892	453,120,55
218	765KV									30,253,440	55,524,130	85,777,57
36	TOTAL						1,012.18	217.92	134		87,314,178.00	1,050,122,701.00	1,137,436,879.0

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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 fc (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 Tra 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 From (a)	To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	Ultimate (g)	CONDUCTORS Size (h)	Specification (i)	Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Tot (p
1	Circuit 6986												2,094,838	(596,688)		1,498
2	Circuit 13806												1,458,371			1,458
3	Circuit 6914												2,497,935			2,497
4	Circuit 6968												6,747,720			6,747
5	Circuit 6946												3,820,333	(15,185)		3,805
6	Circuit 13836												12,131,312	1,980,622		14,111
7	Circuit 6919												4,524,354			4,524
8	Circuit 13826												1,366,521			1,366
9	Circuit 6907												2,022,565	2,022,565		4,045
10	Galena Twp: LaPorte													3,886,268		3,886
11	Circuit 13812												6,530,342	3,185,532		9,715
12	Circuit 6975												1,121,964	200,949		1,322
13	Hudson Twp: LaPorte												13,354,126	4,691,990		18,046
14	Circuit 69-106												5,604,683	16,604		5,621
15	Circuit 138106												1,264	2,125,043		2,126
44	TOTAL		0		0	0	0						63,276,328	17,497,700		80,774

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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 substatic 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 a 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 substa 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, 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. Sp 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 Apparatu Special Equipme: Type of Equipment (i)	Conversion Apparatu Special Equipme: Number of Units (j)
1	Aetna-Lake Co.-Gary	Transmission	Unattended	138	34		224	2		Capacitors	4
2	Ainsworth-Lake Co.-Ross Twp.	Transmission	Unattended	138	12		28	1			
3	Babcock-Porter Co.-Liberty Twp. - a	Transmission	Unattended	138	69		280	2			
4	Babcock-Porter Co.-Liberty Twp. - b	Transmission	Unattended	69	12		56	2			
5	Bailly Gen. Sta.-Porter Co.-Westchester Twp. - a	Transmission	Attended	138		14	45	1		Excitation Xfr	1
6	Bailly Gen. Sta.-Porter Co.-Westchester Twp. - b	Transmission	Attended	138		21	773	2		Excitation Xfr	1
7	Barton Lake-Steuben Co.-James Twp.	Transmission	Unattended	138	69		294	3			
8	Beta Steel Arc Furnace-Porter Co.-Burns Harbor	Transmission	Unattended	138	34		224	2			
9	Burns Ditch-Porter Co.-Portage	Transmission	Unattended	138	34		112	1			
10	Burr Oak-Marshall Co.-Union Twp.	Transmission	Unattended	345	138	14	560	1			
11	Calumet-Lake Co.-Hammond	Transmission	Unattended	138	34		168	2			
12	Chicago Ave.-Lake-Gary	Transmission	Unattended	138	0		5	1			
13	DeKalb-DeKalb Co.-Grant Twp.	Transmission	Unattended	138	69	13	45	1			
14	Dune Acres-Porter Co.-Dune Acres Twp. - a	Transmission	Unattended	345	138	14	560	1			
15	Dune Acres-Porter Co.-Dune Acres Twp. - b	Transmission	Unattended	138	34		224	2		Capacitors	1
16	Eagle Creek - Starke Center	Transmission	Unattended	69						Capacitors	3
17	East Winamac-Pulaski Co.-Monroe Twp.	Transmission	Unattended	138	69		224	2		Capacitors	3
18	Enbridge - Griffith Terminal East	Transmission	Unattended	138	138		59	2			
19	Flint Lake-Porter Co.-Washington Twp. - a	Transmission	Unattended	138	69		336	2		Capacitors	3
20	Flint Lake-Porter Co.-Washington Twp. - b	Transmission	Unattended	138	12		36	1			
21	Flint Lake-Porter Co.-Washington Twp. - c	Transmission	Unattended	69	12		28	1		Capacitors	6
22	Gary Avenue-Lake Co.-Gary	Transmission	Unattended	345	138	14	336	1			
23	Goodland-Newton Co.-Grant Twp.	Transmission	Unattended	138	69		224	2		Capacitors	4
24	Goshen Jct.-Elkhart Co.-Elkhart Twp.	Transmission	Unattended	138	69		336	2		Capacitors	3
25	Grand Army-Marshall Co.-German	Transmission	Unattended	69						Capacitors	2
26	Green Acres-Lake Co.-Ross Twp.	Transmission	Unattended	138	69		336	3	1	Capacitors	3

27	Hartsdale-Lake Co.-Highland - a	Transmission	Unattended	138	69		224	2		Capacitors	3
28	Hartsdale-Lake Co.-Highland - b	Transmission	Unattended	138	12		90	2			
29	Hendricks-Lake Co.-Gary	Transmission	Unattended	138	34		56	1			
30	Highland-Lake Co.-Highland - a	Transmission	Unattended	138	34		224	2		Capacitors	4
31	Highland-Lake Co.-Highland - b	Transmission	Unattended	138	12		28	1			
32	Hiple,F.G.-LaGrange Co.-Eden Twp. - a	Transmission	Unattended	345	138	14	336	1			
33	Hiple,F.G.-LaGrange Co.-Eden Twp. - b	Transmission	Unattended	345	138	14	1040	2			
34	Kenwood-Lake Co.-Hammond	Transmission	Unattended	138	34		224	2		Capacitors	2
35	Kosciusko-Kosciusko Co.-Wayne Twp.	Transmission	Unattended	138	69		336	2		Capacitors	3
36	Kreitzburg-Lake Co.-Hanover Twp.	Transmission	Unattended	138	69		112	1			
37	LaGrange-LaGrange Co.-LaGrange	Transmission	Unattended	138	69		336	2		Capacitors	2
38	Lake George-Lake Co.-Hobart Twp. - a	Transmission	Unattended	138	69		224	2		Capacitors	2
39	Lake George-Lake Co.-Hobart Twp. - b	Transmission	Unattended	345	138		1120	2			
40	Lake George-Lake Co.-Hobart	Transmission	Unattended	138	69		224	2		Capacitors	3
41	Leesburg-Kosciusko Co.-Prairie Twp. - a	Transmission	Unattended	138	69		168	1			
42	Leesburg-Kosciusko Co.-Prairie Twp. - b	Transmission	Unattended	345	138	14	560	1		Capacitors	2
43	Liberty Park-Lake Co.-Center Twp. - a	Transmission	Unattended	138	69		336	2		Capacitors	4
44	Liberty Park-Lake Co.-Center Twp. - b	Transmission	Unattended	69	12		56	2			
45	LNG Plant - LaPorte-Rolling Prarie	Transmission	Attended	138		4	56	2			
46	Lutchman Rd.-LaPorte Co.-Coolspring Twp. - a	Transmission	Unattended	138	69		112	1			
47	Lutchman Rd.-LaPorte Co.-Coolspring Twp. - b	Transmission	Unattended	69	12		22	1			
48	Magnetation - White - Reynolds	Transmission	Unattended	138	69		112	1			
49	Maple-LaPorte Co.-Center Twp. - a	Transmission	Unattended	138	69		224	2		Capacitors	2
50	Maple-LaPorte Co.-Center Twp. - b	Transmission	Unattended	69	12		28	1			
51	Marktown-Lake Co.-East Chicago - a	Transmission	Unattended	138	34	12	90	2		Capacitors	2
52	Marktown-Lake Co.-East Chicago - b	Transmission	Unattended	138	34		112	1			
53	Marktown-Lake Co.-East Chicago - c	Transmission	Unattended	34	12		14	1			
54	Michigan City Gen. Sta.-LaPorte Co.-Michigan City - a	Transmission	Attended	345		21	616	1			
55	Michigan City Gen. Sta.-LaPorte Co.-Michigan City - b	Transmission	Attended	138	34	14	60	1			
56	Michigan City Gen. Sta.-LaPorte Co.-Michigan City - c	Transmission	Attended	138	34	12	60	3			
57	Michigan City Gen. Sta.-LaPorte Co.-Michigan City - d	Transmission	Attended	138		14	168	2			
58	Miller-Lake-Gary	Transmission	Unattended	138							
59	Mitchell Gen. Sta.-Lake Co.-Gary - a	Transmission	Unattended	138	34	14	116	2			
60	Mitchell Gen. Sta.-Lake Co.-Gary - b	Transmission	Unattended	138		15	560	4			
61	Mitchell Gen. Sta.-Lake Co.-Gary - c	Transmission	Unattended	34		13	64	1			
62	Monticello-White Co.-Monticello - a	Transmission	Unattended	138	69	34	224	2			
63	Monticello-White Co.-Monticello - b	Transmission	Unattended	69	12	34	44	2		Capacitors	4
64	Morrison Ditch-Newton Co.-Jefferson	Transmission	Unattended	138							
65	Munster-Lake Co.-Munster - a	Transmission	Unattended	345	138	14	560	1			

66	Munster-Lake Co.-Munster - b	Transmission	Unattended	138	34		224	2			
67	Northeast-Elkhart Co.-Jackson Twp.	Transmission	Unattended	138	69		224	2		Capacitors	6
68	Northport-Noble Co.-Elkhart	Transmission	Unattended	138	69		56	1		Capacitors	3
69	Norway Hydro-White Co.-Union Twp.	Transmission	Unattended	69	2		11	1			
70	Oakdale Hydro-Carroll Co.-Jefferson Twp. - a	Transmission	Unattended	69	12		5	1		Step Volt Reg	3
71	Oakdale Hydro-Carroll Co.-Jefferson Twp. - b	Transmission	Unattended	69		2	16	2			
72	Plymouth-Marshall Co.-Plymouth - a	Transmission	Unattended	138	69		336	2		Capacitors	6
73	Plymouth-Marshall Co.-Plymouth - b	Transmission	Unattended	69	12		56	2			
74	Reynolds-White Co.-Honey Creek Twp. - a	Transmission	Unattended	765	345		3000	3			
75	Reynolds-White Co.-Honey Creek Twp. - b	Transmission	Unattended	345	138	14	350	1			
76	Roxana-Lake Co.-East Chicago - a	Transmission	Unattended	138	34		224	1			
77	Roxana-Lake Co.-East Chicago - b	Transmission	Unattended	34	12		56	2			
78	Schahfer Gen. Sta.-Jasper Co.-Kankakee Twp. - a	Transmission	Attended	345	138	14	336	1		Step Voltage Reg	1
79	Schahfer Gen. Sta.-Jasper Co.-Kankakee Twp. - b	Transmission	Attended	345		23	918	2			
80	Schahfer Gen. Sta.-Jasper Co.-Kankakee Twp. - c	Transmission	Attended	345		21	616	1			
81	Schahfer Gen. Sta.-Jasper Co.-Kankakee Twp. - d	Transmission	Attended	345		17	600	1			
82	Schahfer Gen. Sta.-Jasper Co.-Kankakee Twp. - e	Transmission	Attended	138		14	224	2			
83	Sheffield-Lake Co.-Hammond	Transmission	Unattended	345	138	14	500	1			
84	South Prairie-White Co.-Prairie Twp.	Transmission	Unattended	138	69		168	2			
85	South Valparaiso Porter	Transmission	Unattended	138	69		336	2			
86	St. John-Lake Co.-St. John Twp. - a	Transmission	Unattended	345	138	14	560	1			
87	St. John-Lake Co.-St. John Twp. - b	Transmission	Unattended	138		12	22	1			
88	Starke-Starke Co.-Railroad Twp. - a	Transmission	Unattended	138	69		112	2			
89	Starke-Starke Co.-Railroad Twp. - b	Transmission	Unattended	69	12		14	2		Capacitors	4
90	Starke-Starke Co.-Railroad Twp. - c	Transmission	Unattended	69	12					Step Volt Reg	3
91	Stillwell-LaPorte Co.-Lincoln Twp. - a	Transmission	Unattended	345	138	14	336	1			
92	Stillwell-LaPorte Co.-Lincoln Twp. - b	Transmission	Unattended	138	69		67	1			
93	Sugar Creek-Vigo-West Terre Haute	Transmission	Unattended	345		18	717	3			
94	Taney-Lake Co.-Gary	Transmission	Unattended	138	69		224	2		Capacitors	2
95	Thayer-Newton Co.-Lincoln - a	Transmission	Unattended	138	69		224	2		Capacitors	2
96	Thayer-Newton Co.-Lincoln - b	Transmission	Unattended	69	12		21	2		Step Volt Reg	6
97	Tower Road-Porter Co.-Center Twp.	Transmission	Unattended	345	138	14	350	1			
98	Trail Creek-LaPorte Co.-Michigan City	Transmission	Unattended	138	34		134	2		Capacitors	3
99	Wolf Lake-Lake Co.-Hammond	Transmission	Unattended	138	34		179	2			
100	York Ditch-Elkhart-York	Transmission	Unattended	69						Capacitors	3
101	Angola-Steuben Co.-Angola	Distribution	Unattended	69	12		56	2		Capacitors	5
102	Argos-Marshall Co.-Walnut Twp.	Distribution	Unattended	69	12		7	1		Step Volt Reg	3
103	Ashley-Steuben Co.-Steuben Twp.	Distribution	Unattended	69	12		14	1		Step Volt Reg	3
104	Asphaltum-Jasper Co.-Walker Twp.	Distribution	Unattended	69	12		11	1		Step Volt Reg	3

105	Bass Lake-Starke Co.-California Twp.	Distribution	Unattended	69	12		25	1	1	Step Volt Reg	2
106	BIngo Lake - St. John	Distribution	Unattended	69	12		28	1			
107	Bon Aire-Lake Co.-Ross Twp. - a	Distribution	Unattended	69	12		17	1			
108	Bon Aire-Lake Co.-Ross Twp. - b	Distribution	Unattended	34	12		14	1			
109	Bonneyville-Elkhart Co.-York Twp. - a	Distribution	Unattended	69	12		28	1		Capacitors	1
110	Bonneyville-Elkhart Co.-York Twp. - b	Distribution	Unattended							Step Volt Reg	6
111	Bourbon-Marshall Co.-Bourbon Twp.	Distribution	Unattended	69	12		21	2		Step Volt Reg	2
112	Brighton-LaGrange Co.-Greenfield Twp.	Distribution	Unattended	69	12		11	1		Step Volt Reg	3
113	Bristol-Elkhart Co.-Bristol	Distribution	Unattended	69	12		56	2			
114	Broadmoor-Lake Co.-Munster	Distribution	Unattended	34	12		50	2			
115	Broadway-Lake Co.-Ross Twp.	Distribution	Unattended	69	12		56	2			
116	Brook-Newton Co.-Iroquois Twp.	Distribution	Unattended	69	12		7	1		Step Volt Reg	3
117	Bruce Lake-Fulton Co.-Union Twp.	Distribution	Unattended	69	12		21	2		Step Volt Reg	6
118	Buchanan Street-Lake-Merrillville	Distribution	Unattended	69	69		28	1			
119	Buffalo Pike-White Co.-Union Twp.	Distribution	Unattended	69	12		11	1		Step Volt Reg	3
120	Burdick Road-Porter Co.-Pine Twp.	Distribution	Unattended	69	12		11	1		Step Volt Reg	3
121	Burnettsville-White Co.-Burnettsville	Distribution	Unattended	69	12		7	1		Step Volt Reg	3
122	Buttermilk Corners-Noble Co.-Perry Twp.	Distribution	Unattended	69	12		21	2		Step Volt Reg	6
123	Campus-Porter Co.-Valparaiso	Distribution	Unattended	69	12		28	1			
124	Cedar Lake-Lake Co.-Center Twp.	Distribution	Unattended	69	12		43	2			
125	Center-Marshall Co.-Center Twp.	Distribution	Unattended	69	12		28	2		Step Volt Reg	
126	Central Ave.-Lake Co.-Lake Station - a	Distribution	Unattended	34	12		14	1			
127	Central Ave.-Lake Co.-Lake Station - b	Distribution	Unattended	34	4		4	1			
128	Chase-Lake Co.-Gary	Distribution	Unattended	34	4		8	1			
129	Chesterton-Porter Co.-Chesterton - a	Distribution	Unattended	69	12		28	1			
130	Chesterton-Porter Co.-Chesterton - b	Distribution	Unattended	34	12		28	1			
131	Clark Road-Lake Co.-Gary	Distribution	Unattended	34	4		11	1			
132	Clay-Kosciusko Co.-Clay Twp.	Distribution	Unattended	69	12		21	1	1	Step Volt Reg	3
133	Cleveland-Lake Co.-Calumet Twp.	Distribution	Unattended	34	4		7	1			
134	Cline-Lake Co.-Highland	Distribution	Unattended	34	12		22	1			
135	Clunette-Kosciusko Co.-Scott Twp.	Distribution	Unattended	69	12		7	1		Step Volt Reg	
136	Colfax-Lake Co.-Calumet Twp.	Distribution	Unattended	34	12		14	1			
137	College-Jasper Co.-Marion Twp.	Distribution	Unattended	69	12		7	1		Step Volt Reg	3
138	Columbia Ave.-Lake Co.-Hammond	Distribution	Unattended	34	12		22	1			
139	Coolspring-LaPorte Co.-Coolspring Twp.	Distribution	Unattended	34	12		21	2		Step Volt Reg	6
140	Cornell-Porter Co.-Boone Twp. - a	Distribution	Unattended	69	12		7	1		Capacitors	1
141	Cornell-Porter Co.-Boone Twp. - b	Distribution	Unattended							Step Volt Reg	3

142	Court-Lake Co.-Crown Point	Distribution	Unattended	69	12		56	2			
143	Creston-Lake Co.-West Creek Twp.	Distribution	Unattended	69	12		56	2		Step Volt Reg	3
144	Crocker-Porter Co.-Porter	Distribution	Unattended	34	12		28	2			
145	Crystal Valley-Elkhart Co.-Middlebury	Distribution	Unattended	69	12		11	1		Step Volt Reg	3
146	Culver-Marshall Co.-Culver	Distribution	Unattended	69	12		21	1	1	Step Volt Reg	6
147	Decatur-Lake Co.-Gary - a	Distribution	Unattended	34	12		10	1			
148	Decatur-Lake Co.-Gary - b	Distribution	Unattended	34	4		7	1			
149	Deep River-Porter Co.-Union Twp.	Distribution	Unattended	69	12		28	1	1		
150	Deer Run-LaPorte Co.-Washington Twp.	Distribution	Unattended	69	12		21	2		Step Volt Reg	3
151	Delaware-Lake Co.-Gary	Distribution	Unattended	34	12		14	1			
152	DeMotte-Jasper Co.-Keener Twp.	Distribution	Unattended	69	12		25	1		Step Volt Reg	6
153	Dierdorff Road-Elkhart Co.-Elkhart Twp.	Distribution	Unattended	69	12		28	1			
154	Division-LaPorte Co.-Center Twp.	Distribution	Unattended	69	12		17	1			
155	Donaldson-Marshall Co.-West Twp.	Distribution	Unattended	69	12		3	1		Step Volt Reg	3
156	Dyer-Lake Co.-Dyer - a	Distribution	Unattended	69	12		28	1			
157	Dyer-Lake Co.-Dyer - b	Distribution	Unattended	34	12		22	1			
158	East Gary-Lake Co.-Lake Station - a	Distribution	Unattended	69	12		22	1			
159	East Gary-Lake Co.-Lake Station - b	Distribution	Unattended	34	12		11	1			
160	East Walkerton-St. Joseph Co.-Walkerton	Distribution	Unattended	69	12		28	2		Step Volt Reg	6
161	Edgewater-Lake Co.-Merrillville	Distribution	Unattended	69	12		28	1			
162	Eighth St.-LaPorte Co.-Michigan City	Distribution	Unattended	34	12		45	2			
163	Elliott-Lake Co.-Munster	Distribution	Unattended	34	12		28	1			
164	Elm-Lake Co.-East Chicago	Distribution	Unattended	34	4		10	2	2		
165	Elmwood-Lake Co.-Hammond	Distribution	Unattended	34	12		14	1			
166	Evans-Porter Co.-Valparaiso	Distribution	Unattended	69	12		45	2			
167	Fail Road-LaPorte Co-Kankakee Twsp	Distribution	Unattended	69	12		14	1			
168	Fairbanks-Lake Co.-Gary	Distribution	Unattended	34	4		6	1			
169	Fayette-Lake Co.-Hammond	Distribution	Unattended	34	4		11	1			
170	Fish Lake-LaPorte Co.-Lincoln Twp.	Distribution	Unattended	69	12		6	1		Step Volt Reg	3
171	Fisher-Lake Co.-Munster	Distribution	Unattended	34	12		56	2			
172	Fortieth Ave.-Lake Co.-Gary	Distribution	Unattended	34	4		11	1			
173	Forty-Ninth Ave.-Lake Co.-Gary	Distribution	Unattended	34	4		8	1			
174	Fowler-Benton Co.-Fowler	Distribution	Unattended	69	12		11	1	1	Step Volt Reg	3
175	Fremont-Steuben Co.-Fremont	Distribution	Unattended	69	12		56	2		Capacitors	2
176	Freyer-LaPorte Co.-Michigan City	Distribution	Unattended	34	12		25	2		Step Volt Reg	6
177	Furnessville-Porter Co.-Westchester Twp.	Distribution	Unattended	34	12		11	1	1	Step Volt Reg	3
178	Gary Heights-Lake Co.-Gary	Distribution	Unattended	34	4		6	1			
179	Gibson-Lake Co.-Hammond	Distribution	Unattended	34	12		22	1			
180	Gleason-Lake Co.-Gary - a	Distribution	Unattended	34	12		14	1			
181	Gleason-Lake Co.-Gary - b	Distribution	Unattended	34	12		9	1			
182	Glen Park-Lake Co.-Calumet Twp.	Distribution	Unattended	34	12		14	1			

183	Goodland Jct.-Newton Co.-Grant Twp.	Distribution	Unattended	69	12		14	2		Step Volt Reg	3
184	Grand Trunk-Porter Co.-Center	Distribution	Unattended	69	12		28	1			
185	Greenway-LaPorte Co.-LaPorte	Distribution	Unattended	69	12		56	2			
186	Griffith-Lake Co.-Griffith	Distribution	Unattended	34	12		17	1			
187	Guernsey-White Co.-Union Twp.	Distribution	Unattended	69	12		14	2		Step Volt Reg	6
188	Guthrie-Lake Co.-East Chicago	Distribution	Unattended	34	12		28	2			
189	Hager-Lake Co.-Cedar Lake	Distribution	Unattended	69	12		28	1			
190	Hamilton-Lake Co.-Gary	Distribution	Unattended	34	4		7	1			
191	Hamlet-Starke Co.-Oregon Twp.	Distribution	Unattended	69	12		14	2		Step Volt Reg	3
192	Hanna-LaPorte Co.-Hanna Twp.	Distribution	Unattended	69	12		11	1	1	Step Volt Reg	3
193	Hanover-Lake Co.-Hanover Twp.	Distribution	Unattended	69	12		28	2			
194	Harrison-Lake Co.-Hammond	Distribution	Unattended	34	12		28	2			
195	Hebron-Porter Co.-Hebron	Distribution	Unattended	69	12		21	1	1	Step Volt Reg	6
196	Helmer-Steuben Co.-Salem Twp.	Distribution	Unattended	69	12		14	1	1	Step Volt Reg	6
197	Hessville-Lake Co.-Hammond	Distribution	Unattended	34	12		22	1			
198	Highland Shopping Center-Lake Co.-Highland	Distribution	Unattended	34	12		3	1			
199	Hillside-Jasper Co.-DeMotte	Distribution	Unattended	69	12		7	1		Step Volt Reg	3
200	Hobart-Lake Co.-Hobart	Distribution	Unattended	69	12		50	2			
201	Hobart Road-Lake Co.-Gary	Distribution	Unattended	34	4		7	1			
202	Honey Creek-White Co.-Honey Creek Twp.	Distribution	Unattended	69	12		10	2		Step Volt Reg	6
203	Hoosier Hill-Steuben Co.-Angola	Distribution	Unattended	69	12		21	2		Step Volt Reg	6
204	Horn Ditch-Elkhart Co.-Clinton Twp.	Distribution	Unattended	69	12		22	1			
205	Howe-LaGrange Co.-Lima Twp.	Distribution	Unattended	69	12		28	2		Step Volt Reg	6
206	Hudson-Steuben Co.-Ashley	Distribution	Unattended	69	12		14	1		Step Volt Reg	3
207	Hyde Park-Lake Co.-Calumet Twp. - a	Distribution	Unattended	34	12		36				
208	Hyde Park-Lake Co.-Calumet Twp. - b	Distribution	Unattended	34	4		7	1			
209	Idaho-Lake Co.-Gary	Distribution	Unattended	34	12		14	1			
210	Idaville-White Co.-Lincoln Twp.	Distribution	Unattended	69	12		5	1		Step Volt Reg	3
211	Illinois-Elkhart Co.-Goshen	Distribution	Unattended	69	12		56	2			
212	Independence Hill-Lake Co.-Ross Twp.	Distribution	Unattended	69	12		56	2			
213	Indian Boundary-Lake Co.-Gary	Distribution	Unattended	34	12		14	1			
214	Indian Creek-Elkhart Co-Jefferson Twp	Distribution	Unattended	69	12		14	1			
215	Indiana Harbor-Lake Co.-East Chicago	Distribution	Unattended	34	12		28	2			
216	Ironwood-Marshall Co.-Center Twp.	Distribution	Unattended	69	12		4	1		Step Volt Reg	3
217	James-Steuben Co.-Pleasant Twp.	Distribution	Unattended	69	12		21	2		Step Volt Reg	3
218	Johnson-Lake Co.-Gary	Distribution	Unattended	34	12		14	1			
219	Karwick Road-LaPorte Co.-Coolspring	Distribution	Unattended	34	12		11	1		Step Volt Reg	3

220	Keffer-LaPorte-Michigan City	Distribution	Unattended	34	12		28	1			
221	Kentland-Newton Co.-Kentland	Distribution	Unattended	69	12		11	1	1	Step Volt Reg	2
222	Kentucky-LaPorte Co.-Michigan City	Distribution	Unattended	34	12		45	2			
223	Kingsbury-LaPorte Co.-Kingsbury	Distribution	Unattended	69	12		14	1		Step Volt Reg	3
224	Kingsford Heights-LaPorte Co.-Kingsford Heights	Distribution	Unattended	69	12		6	1		Step Volt Reg	3
225	Knox-Starke Co.-Knox	Distribution	Unattended	69	12		29	3		Step Volt Reg	9
226	Knox Jct.-Marshall Co.-West Twp.	Distribution	Unattended	69	12		7	1		Step Volt Reg	3
227	Lake Hills-Lake Co.-St. John Twp.	Distribution	Unattended	69	12		28	1	1		
228	Lakeland-LaPorte Co.-Michigan City	Distribution	Unattended	34	12		11	1		Step Volt Reg	3
229	LaPorte-LaPorte Co.-LaPorte	Distribution	Unattended	69	12		56	2			
230	Lawton-Pulaski Co.-Tippecanoe Twp.	Distribution	Unattended	69	12		7	1		Step Volt Reg	3
231	Liable-Lake Co.-Highland	Distribution	Unattended	34	12		14	1			
232	Lindbergh-Lake Co.-Hammond	Distribution	Unattended	34	12		28	2			
233	Lincoln Square-Lake Co.-North Twp.	Distribution	Unattended	69	12		45	2			
234	Link-Pulaski Co.-Indian Creek Twp.	Distribution	Unattended	69	12		11	1		Step Volt Reg	3
235	Louisiana-Lake Co.-Gary	Distribution	Unattended	34	4		7	1			
236	Lowell-Lake Co.-Lowell	Distribution	Unattended	69	12		56	2			
237	Madison-Lake Co.-Gary	Distribution	Unattended	34	12		45	2			
238	Malden-Porter Co.-Morgan Twp.	Distribution	Unattended	69	12		21	2		Step Volt Reg	6
239	Maplewood-Lake Co.-Crown Point	Distribution	Unattended	69	12		22	1			
240	Marshall-Marshall Co.-North Twp.	Distribution	Unattended	69	34		8	1			
241	Mason Ave.-Lake Co.-Gary	Distribution	Unattended	34	12		11	1		Step Volt Reg	3
242	Maynard-Lake Co.-Munster	Distribution	Unattended	34	12		50	2			
243	McCool-Porter Co.-Porter	Distribution	Unattended	69	12		56	2			
244	McKinley-Kosciusko Co.-Warsaw	Distribution	Unattended	69	12		56	2			
245	Meadow Lane-Lake-Dyer	Distribution	Unattended	69	12		39	1			
246	Medaryville-Pulaski Co.-Medaryville	Distribution	Unattended	69	12		6	1	1	Step Volt Reg	3
247	Mentone-Kosciusko Co.-Mentone	Distribution	Unattended	69	12		14	2		Step Volt Reg	6
248	Merlin St.-Lake Co.-Hammond	Distribution	Unattended	34	12		5	1		Step Volt Reg	3
249	Merrillville-Lake Co.-Ross Twp.	Distribution	Unattended	69	12		45	2			
250	Middlebury-Elkhart Co.-Middlebury	Distribution	Unattended	69	12		45	2			
251	Midway-Elkhart Co.-Jefferson Twp.	Distribution	Unattended	69	12		11	1		Step Volt Reg	3
252	Milford-Kosciusko Co.-Milford	Distribution	Unattended	69	12		21	2		Step Volt Reg	6
253	Milroy-Jasper Co.-Milroy Twp.	Distribution	Unattended	69	12		7	1		Step Volt Reg	3
254	Mississippi-Lake Co.-Hobart Twp. - a	Distribution	Unattended	69	12		14	1			
255	Mississippi-Lake Co.-Hobart Twp. - b	Distribution	Unattended	34	12		22	1			
256	Mobile Sub. No.2-Porter Co.-Washington Twp. - a	Distribution	Unattended	69	12		15	1			
257	Mobile Sub. No 3-Porter Co.-Washington Twp. - b	Distribution	Unattended	69	12		20	1			

258	Mobile Sub. No 4-Porter Co.-Washington Twp. - c	Distribution	Unattended	69	12		15	1			
259	Model-Elkhart Co.-Goshen	Distribution	Unattended	69	12		56	2			
260	Monon-White Co.-Monon	Distribution	Unattended	69	12		21	2		Step Volt Reg	6
261	Monoquet-Kosciusko Co.-Plain Twp.	Distribution	Unattended	69	12		21	1		Step Volt Reg	6
262	Montgomery-Lake Co.-Gary	Distribution	Unattended	34	12		14	1			
263	Moody-Jasper Co.-Barkley Twp.	Distribution	Unattended	69	12		3	1		Step Volt Reg	3
264	Morocco-Newton Co.-Morocco	Distribution	Unattended	69	12		21	2			
265	Nappanee-Elkhart Co.-Nappanee	Distribution	Unattended	69	12		56	2		Step Volt Reg	9
266	Nealon Drive-Porter-Portage	Distribution	Unattended	34	12		28	1			
267	Nevada Mills-Steuben Co.-Jamestown Twp.	Distribution	Unattended	69	12		7	1		Step Volt Reg	3
268	New Chicago-Lake Co.-Hobart Twp.	Distribution	Unattended	34	4		7	1			
269	New Paris-Elkhart Co.-Jackson Twp.	Distribution	Unattended	69	12		28	2		Step Volt Reg	6
270	Newbury-LaGrange Co.-Newbury Twp.	Distribution	Unattended	69	12		28	2		Step Volt Reg	5
271	North Hammond-Lake Co.-Hammond	Distribution	Unattended	34	12		14	1			
272	North Judson-Starke Co.-North Judson	Distribution	Unattended	69	12		22	3			
273	North Liberty-St. Joseph Co.-North Liberty	Distribution	Unattended	69	12		14	2		Step Volt Reg	6
274	North Webster-Kosciusko Co.-North Webster	Distribution	Unattended	69	12		21	2		Step Volt Reg	6
275	Northridge-Elkhart Co.-Middlebury	Distribution	Unattended	69	12		14	1		Step Volt Reg	3
276	Northwood-Elkhart Co.-Locke Twp.	Distribution	Unattended	69	12		28	1			
277	Novak Road-Lake Co.-St. John	Distribution	Unattended	69	12		28	1			
278	O'Leary-Lake Co.-Merrillville	Distribution	Unattended	69	12		28	1			
279	Ohio-LaPorte Co.-Michigan City	Distribution	Unattended	34	12		45	2		Step Volt Reg	6
280	One Twentieth St.-Lake Co.-Hammond	Distribution	Unattended	34	12		14	1			
281	Orchard Grove-Lake Co.-Cedar Creek Twp.	Distribution	Unattended	69	12		42	2			
282	Oswego-Kosciusko Co.-Plain Twp.	Distribution	Unattended	69	12		11	2		Step Volt Reg	3
283	Palmira Lake-Hanover Twp.	Distribution	Unattended	69	12		28	1			
284	Parr-Jasper Co.-Union Twp. - a	Distribution	Unattended	69	12		5	1		Capacitors	3
285	Parr-Jasper Co.-Union Twp. - b	Distribution	Unattended							Step Volt Reg	3
286	Pidco-Marshall Co.-Plymouth	Distribution	Unattended	69	12		28	1			
287	Pierceton-Kosciusko Co.-Pierceton	Distribution	Unattended	69	12		20	1	1	Step Volt Reg	6
288	Pine Creek-Benton Co.-Grant Twp.	Distribution	Unattended	69	12		8	1	1	Step Volt Reg	3
289	Pine Manor-Elkhart Co.-Elkhart Twp.	Distribution	Unattended	69	12		56	2			
290	Pinola-LaPorte Co.-Scipio Twp.	Distribution	Unattended	69	12		11	1		Step Volt Reg	3
291	Plum Creek-Lake Co.-Dyer	Distribution	Unattended	69	12		28	1			
292	Port of Indiana-Porter Co.-Burns Harbor	Distribution	Unattended	34	12		21	2		Step Volt Reg	6
293	Prairie Park-Lake Co.-East Chicago	Distribution	Unattended	34	12		14	1			

294	Pullman-Standard-Lake Co.-Hammond	Distribution	Unattended	34	12		28	1				
295	Rand-Lake Co.-Hobart	Distribution	Unattended	69	12		31	2				
296	Remington-Jasper Co.-Remington	Distribution	Unattended	69	12		14	1	1	Step Volt Reg	6	
297	Ridge Road-Lake Co.-Griffith	Distribution	Unattended	34	12		22	1				
298	Robertsdale-Lake Co.-Hammond	Distribution	Unattended	34	12		14	1				
299	Rock Run-Elkhart Co.-Goshen	Distribution	Unattended	69	12		56	2				
300	Rolilng Hills	Distribution	Unattended	69	12		28	1				
301	Ross-Lake Co.-Calumet Twp.	Distribution	Unattended	69	12		14	1				
302	Rozella-Kosciusko Co.-Warsaw	Distribution	Unattended	69	12		11	1		Step Volt Reg	3	
303	Salem-Pulaski Co.-Francesville	Distribution	Unattended	69	12		11	1	1	Step Volt Reg	3	
304	Sand Creek-Porter Co.-Liberty	Distribution	Unattended	69	12		28	1				
305	Schererville-Lake Co.-Schererville	Distribution	Unattended	69	12		56	2				
306	Schneider-Lake Co.-Schneider	Distribution	Unattended	69	12		21	2		Step Volt Reg	3	
307	Shilo-Marshall Co.-Polk Twp.	Distribution	Unattended	69	12		6	1		Step Volt Reg	3	
308	Sibley-Lake Co.-Hammond	Distribution	Unattended									
309	Silhavy-Washington-Porter	Distribution	Unattended	69	12		28	1				
310	Sixty-First Ave.-Lake Co.-Ross Twp.	Distribution	Unattended	69	12		50	2				
311	Smith Ditch-Porter Co.-Center Twp.	Distribution	Unattended	69	12		28	1				
312	South Chalmers-White Co.-Big Creek Twp.	Distribution	Unattended	69	12		14	2		Step Volt Reg	6	
313	South Hammond-Lake Co.-Hammond	Distribution	Unattended	34	12		56	2				
314	South Haven-Porter Co.-Portage Twp.	Distribution	Unattended	69	12		50	2				
315	South Lake-Lake Co.-Ross Twp.	Distribution	Unattended	69	12		56	2				
316	South Milford-LaGrange Co.-Milford Twp.	Distribution	Unattended	69	12		11	1	1	Step Volt Reg	3	
317	Spectacle Lake-Porter Co.-Center Twp.	Distribution	Unattended	69	12		45	2				
318	Spring-LaGrange Co.-LaGrange	Distribution	Unattended	69	12		21	2		Step Volt Reg	6	
319	Springwood-LaPorte Co.-Michigan City	Distribution	Unattended	34	12		14	1				
320	Star Milling-LaGrange Co.-Lima Twp.	Distribution	Unattended	12	2		0	3				
321	Summit-LaPorte Co.-Center Twp.	Distribution	Unattended	69	12		11	1		Step Volt Reg	3	
322	Syracuse-Kosciusko Co.-Syracuse	Distribution	Unattended	69	12		25	2		Step Volt Reg	6	
323	Third St.-Marshall Co.-Bremen - a	Distribution	Unattended	69	12		14	2		Capacitors	2	
324	Third St.-Marshall Co.-Bremen - b	Distribution	Unattended							Step Volt Reg	6	
325	Tilden-LaPorte Co.-Michigan City	Distribution	Unattended	34	12		28	2				
326	Tod-Lake Co.-East Chicago	Distribution	Unattended	34	12		28	1				
327	Tompkins-Lake Co.-Gary - a	Distribution	Unattended	34	12		28	1				
328	Tompkins-Lake Co.-Gary - b	Distribution	Unattended	34	4		8	1				
329	Topeka-LaGrange Co.-Topeka	Distribution	Unattended	69	12		13	1		Step Volt Reg	3	
330	Torrence-Lake Co.-Hammond	Distribution	Unattended	34	12		14	1				
331	Township-Porter Co.-Liberty Twp.	Distribution	Unattended	69	12		28	1				
332	Twin Lakes-White Co.-Monticello	Distribution	Unattended	69	12		28	1				

333	University-Lake Co.-Gary	Distribution	Unattended	34	12		10	1			
334	Veterans Highway-Lake Co.-Crown Pt	Distribution	Unattended	69	12		28	1			
335	Virginia-Lake Co.-Gary	Distribution	Unattended	34	12		36	2			
336	Waite-Lake Co.-Gary	Distribution	Unattended	34	12		14	1			
337	Wakarusa-Elkhart Co.-Harrison	Distribution	Unattended	69	12		32	3		Step Volt Reg	9
338	Wanatah-LaPorte Co.-Wanatah	Distribution	Unattended	69	12		11	1		Step Volt Reg	3
339	Warner Rd.-Elkhart Co.-Syracuse	Distribution	Unattended	69	12		14	1		Step Volt Reg	3
340	Warsaw-Kosciusko Co.-Warsaw	Distribution	Unattended	69	12		56	2			
341	Washington-Porter Co.-Valparaiso	Distribution	Unattended	69	12		56	2			
342	Waterloo-DeKalb Co.-Waterloo	Distribution	Unattended	69	12		21	2	1	Step Volt Reg	6
343	Wawasee-Kosciusko Co.-Turkey Creek Twp.	Distribution	Unattended	69	12		11	1		Step Volt Reg	3
344	Wayne-Kosciusko Co.-Wayne Twp.	Distribution	Unattended	69	12		22	1	1		
345	Weirick-Kosciusko Co.-Harrison Twp.	Distribution	Unattended	69	12		5	1		Step Volt Reg	3
346	West Point-White Co.-West Point Twp.	Distribution	Unattended	69	12		7	1		Step Volt Reg	
347	Westville-LaPorte Co.-Portage Twp.	Distribution	Unattended	69	12		21	2		Step Volt Reg	4
348	Wheeler-Porter Co.-Portage Twp.	Distribution	Unattended	69	12		52	2			
349	Whiting-Lake Co.-Whiting	Distribution	Unattended	34	12		14	1			
350	Wickliffe-Porter Co.-Ogden Dunes	Distribution	Unattended	34	12		21	2		Step Volt Reg	6
351	Williamsburg-Porter Co.-Washington Twp.	Distribution	Unattended	69	12		14	1			
352	Willow Court-Lake Co.-Hammond	Distribution	Unattended	34	12		28	1			
353	Willowdale-Porter Co.-Portage	Distribution	Unattended	69	12		28	1			
354	Wilson-Lake Co.-Gary	Distribution	Unattended	34	12		14	1			
355	Winamac-Pulaski Co.-Winamac	Distribution	Unattended	69	12		21	2	1	Capacitors	2
356	Wolcottville-LaGrange Co.-Wolcottville	Distribution	Unattended	69	12		21	2		Step Volt Reg	6
357	Woodland Park-Porter Co.-Portage	Distribution	Unattended	69	12		22	1			
358	Woodmar-Lake Co.-Hammond	Distribution	Unattended	34	12		28	1			
359	Wooster-Kosciusko Co.-Wayne	Distribution	Unattended	69	12		11	1		Step Volt Reg	3
360	TotalDistributionSubstationMember							347	22		427
361	TotalGenerationSubstationMember							0	0		0
362	TotalTransmissionSubstationMember							155	1		109
363	Total							502	23		536

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ 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	[a] Outside services employed (1)	NiSource Corporate Services Company	923	72,739,736
3	Adminstrative and general salaries (2)	NiSource Corporate Services Company	920	68,752,189
4	Contsruction work in progress (3)	NiSource Corporate Services Company	107	65,117,052
5	Maintenance of general plant	NiSource Corporate Services Company	932	18,064,369
6	Rent expenses	NiSource Corporate Services Company	931	5,120,600
7	Office supplies and expenses	NiSource Corporate Services Company	921	2,759,460
8	Customer records and collection expenses	NiSource Corporate Services Company	903	2,041,127
9	Other regulatory assets	NiSource Corporate Services Company	182.3	935,782
10	Injuries and damages	NiSource Corporate Services Company	925	678,289
11	Misc cust serv and information	NiSource Corporate Services Company	910	387,405
12	Miscellaneous general expenses	NiSource Corporate Services Company	930.2	363,163
13	General advertising expenses	NiSource Corporate Services Company	930.1	183,017
14	Advertising expenses	NiSource Corporate Services Company	913	65,011
15	Property insurance	NiSource Corporate Services Company	924	27,135
16	Demonstrating and selling expenses	NiSource Corporate Services Company	912	1,511
17	Regulatory commission expenses	NiSource Corporate Services Company	928	876
18	Customer acccount supervsion expenses	NiSource Corporate Services Company	901	516
19	Preliminary survey and investigation charges	NiSource Corporate Services Company	183	(4,350)
20	Interest expense	NiSource	430	121,561,727
21	Employee pensions and benefits	NiSource	926	1,509,219
22	Interest income	NiSource	419	
23	Injuries and damages	NiSource Insurance Corporation	925	5,956,053
24	Prepaid property insurance	NiSource Insurance Corporation	165	3,535,593
25	Employee pensions and benefits	NiSource Insurance Corporation	926	2,905,886
26	Property insurance	NiSource Insurance Corporation	924	550,961
27	Rent expense	NiSource Development Company	931	3,430,962
28			Total	3,430,962
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Financing services	NIPSCO Accounts Receivable Corp.	426	6,808,882
22	Interest income	NIPSCO Accounts Receivable Corp.	419	(995,521)
42				

Name of Respondent: Northern Indiana Public Service Company LLC	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/17/2023	Year/Period of Report End of: 2022/ Q4

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.