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) Black Hills Power Inc.	Year/Period of Report End of: 2023/ Q4

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

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

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

VII. For any resubmissions, 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;

"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 Black Hills Power Inc.	02 Year/ Period of Report End of: 2023/ 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) 7001 Mt Rushmore Road, Rapid City, SD 57702	
05 Name of Contact Person Nick Wagner	06 Title of Contact Person Vice President Regulatory
07 Address of Contact Person (Street, City, State, Zip Code) 1515 Arapahoe Road, Tower One, Suite 1200, Denver CO 80202	

08 Telephone of Contact Person, Including Area Code (303)566-3529	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 12/31/2023

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 Courtney Hebert	03 Signature Courtney Hebert	04 Date Signed (Mo, Da, Yr) 04/04/2024
02 Title Vice President - Corporate Controller		

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: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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".

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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.

Kimberly F. Nooney

Sr. Vice President, Chief Financial Officer

7001 Mt. Rushmore Rd., Rapid City, SD 57702

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: SD

Date of Incorporation: 1941-08-27

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 Service - South Dakota, Wyoming, Montana

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: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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.

Respondent is a wholly-owned, direct subsidiary of Black Hills Corporation. At December 31, 2023, Black Hills Corporation owned 100% of the common stock of Respondent.

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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				
2				
3				
4				
5				
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12				
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14				
15				

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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 and Chief Executive Officer	Linden R. Evans	900,000		
2	Sr. Vice President and Chief Financial Officer	Richard W. Kinzley	472,000		2023-07-03
3	Sr. Vice President and Chief Financial Officer	Kimberly F. Nooney	440,000	2023-04-01	
4	Sr. Vice President and General Counsel	Brian G. Iverson	433,000		
5	Sr. Vice President - Chief Human Resources Officer	Jennifer C. Landis	348,000		2023-04-03
6	Sr. Vice President - Utilities	Marne M. Jones	398,000	2023-06-12	
7	Sr. Vice President - Chief Information Officer	Erik D. Keller	368,000		
8	Sr. Vice President - Growth and Strategy	Todd Jacobs	394,250	2023-06-12	
9	Vice President - Black Hills Energy South Dakota	Marc Eyre	230,000		2023-06-12
10	Vice President - Black Hills Energy South Dakota and Wyoming	Wes Ashton	236,200	2023-06-12	

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)
1	Linden R. Evans (President and CEO)	Black Hills Corporation, 7001 Mt. Rushmore Rd., Rapid City, SD 57702	false	false
2	Kimberly F. Nooney (Sr. Vice President and CFO)	Black Hills Corporation, 7001 Mt. Rushmore Rd., Rapid City, SD 57702	false	false
3	Brian G. Iverson (Sr. Vice President and General Counsel)	Black Hills Corporation, 7001 Mt. Rushmore Rd., Rapid City, SD 57702	false	false

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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	BHP JOATT, Attachment H, BHP AC Transmission Formula rate and BHP Formula Rate Protocols and Schedule 1	ER18-1583-000, ER14-2689-000, ER08-1584-000
2	[a] BHP JOATT, Schedule 2	ER15-2366-000, ER09-1292

FOOTNOTE DATA

(a) Concept: RateScheduleTariffNumber
BHP Protocols do not require an annual filing for Schedule 2, page 106b is blank as Schedule 2 inputs match FF1 inputs.

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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	20230228-5391	02/28/2022	ER23-1200-000	Annual Informational Filing, Black Hills Power Attachment H, AC Transmission System Formula Rate	Attachment H and Schedule 1
2	20240227-5227	02/27/2024	ER24-1356-00	Informational Filing: Annual Formula Rate Update	Attachment H and Schedule 1

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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)
1				

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1. None.

2. None.

3. None.

4. None.

5. None.

6. Not applicable.

7. None.

8. The average annual union wage increase for Black Hills Power during 2023 was 3.03%. The average non-union wage increase was 4.15%.

9. None.

10. None.

12. None.

13. The following changes in officers occurred during the year:

a) Richard W. Kinzley's title changed from Senior Vice President – Chief Financial Officer to Senior Vice President effective April 1, 2023, and retired effective July 3, 2023

b) Kimberly F. Nooney's title changed from Vice President – Treasurer to Senior Vice President – Chief Financial Officer and Treasurer effective April 1, 2023, and to Senior Vice President – Chief Financial Officer effective June 12, 2023

c) Jennifer C. Landis, Senior Vice President – Chief Human Resources Officer, was removed as an Officer effective April 3, 2023

d) Todd Jacobs' title changed from Vice President – Growth and Strategy to Senior Vice President – Growth and Strategy effective June 12, 2023

e) Marne M. Jones' title changed from Vice President - Electric Utilities to Senior Vice President – Utilities effective June 12, 2023

f) Tom D. Stevens' title changed from Vice President – Regulatory to Vice President – Treasurer effective June 12, 2023

g) Nick Wagner was appointed Vice President – Regulatory effective June 12, 2023

h) Brett Anderson's title changed from Vice President – Supply Chain to Vice President – Utility Services effective June 12, 2023

i) Wes Ashton's title changed from Vice President – Customer Experience to Vice President – BHE South Dakota and Wyoming effective June 12, 2023

j) Courtney Hebert's title changed from Vice President – Corporate Controller and Chief Risk Officer to Vice President – Corporate Controller effective June 12, 2023

k) Marc Eyre, Vice President - Black Hills Energy South Dakota, was removed as an Officer effective June 12, 2023.

14. Not applicable.

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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	1,768,004,812	1,698,479,177
3	Construction Work in Progress (107)	200	19,809,320	48,030,468
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,787,814,132	1,746,509,645
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	518,023,276	490,911,234
6	Net Utility Plant (Enter Total of line 4 less 5)		1,269,790,856	1,255,598,411
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)		1,269,790,856	1,255,598,411
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)			
19	(Less) Accum. Prov. for Depr. and Amort. (122)			
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		828,691	698,691
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		3,053,090	2,979,053
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)			
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		3,881,781	3,677,744
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)			731,209
36	Special Deposits (132-134)			
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		17,006,222	23,336,758
41	Other Accounts Receivable (143)		1,997,150	988,316
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		139,482	181,889
43	Notes Receivable from Associated Companies (145)		13,623,211	
44	Accounts Receivable from Assoc. Companies (146)		11,490,800	29,000,357
45	Fuel Stock (151)	227	7,162,936	2,559,027
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	32,979,902	30,032,094
49	Merchandise (155)	227		170
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	3,561,730	2,078,990
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		4,086,489	3,992,256
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			

61	Accrued Utility Revenues (173)		12,197,305	13,414,974
62	Miscellaneous Current and Accrued Assets (174)		266,843	5,093,249
63	Derivative Instrument Assets (175)			
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		104,233,106	111,045,511
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		1,984,513	2,117,404
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	70,380,555	73,978,545
73	Prelim. Survey and Investigation Charges (Electric) (183)			
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)		1,689,858	307,531
76	Clearing Accounts (184)		978,773	821,008
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	5,830,961	5,606,926
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		128,780	313,740
82	Accumulated Deferred Income Taxes (190)	234	[a]48,503,497	44,839,608
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		129,496,937	127,984,762
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,507,402,680	1,498,306,428

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Note: Amounts footnoted are based upon FERC-approved rates

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Abandonment Loss	(104,894)	(4,571)
3	Bad Debt Reserve	1,022,942	718,682
4	Bonus Compensation	189,354	289,803
5	Deferred Compensation	94,533	91,246
6	Defined Benefit Pension Plan	4,348,267	4,449,922
7	Defined Benefit Pension Plan AOCI	64,911	66,534
8	Line Extension Deposits	2,239,526	1,522,250
9	Net Operating Loss Carryforward	2,741,398	3,219,238
10	Non-qualified Pension Plan	260,469	221,227
11	Operating Leases	2,825,794	2,766,304
12	Production Tax Credits	7,988,949	11,577,888
13	Regulatory Liabilities	19,034,294	18,073,934
14	Retiree Healthcare Plan	1,038,433	1,003,838
15	Other	3,095,632	4,012,600
16	TOTAL Electric (Enter Total of lines 2 thru 7)	44,839,608	48,008,895
17			
18			
19	Gas		
20			
21			
22			
23	Other		
24	TOTAL Gas (Enter of lines 10 thru 15)		
25	Other (Specify)		
26	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	44,839,608	48,008,895

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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	23,416,396	23,416,396
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)		42,076,811	42,076,811
7	Other Paid-In Capital (208-211)	253		
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b	2,501,882	2,501,882
11	Retained Earnings (215, 215.1, 216)	118	526,043,810	488,385,201
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118		
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(761,474)	(782,536)
16	Total Proprietary Capital (lines 2 through 15)		588,273,661	550,593,990
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	340,000,000	340,000,000
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256		
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		65,550	69,690
24	Total Long-Term Debt (lines 18 through 23)		339,934,450	339,930,310
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		12,826,427	13,128,976
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		331,970	539,066
29	Accumulated Provision for Pensions and Benefits (228.3)		9,275,803	8,684,170
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		832,828	807,859
35	Total Other Noncurrent Liabilities (lines 26 through 34)		23,267,028	23,160,071
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)			
38	Accounts Payable (232)		18,349,819	29,935,771
39	Notes Payable to Associated Companies (233)		190,651,875	207,715,652
40	Accounts Payable to Associated Companies (234)		37,649,001	44,591,052
41	Customer Deposits (235)		6,386,793	1,847,452
42	Taxes Accrued (236)	262	7,509,986	8,025,124
43	Interest Accrued (237)		4,702,201	4,675,246
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		909,873	1,179,277
48	Miscellaneous Current and Accrued Liabilities (242)		7,382,029	8,070,004
49	Obligations Under Capital Leases-Current (243)		346,448	327,187
50	Derivative Instrument Liabilities (244)			
51	(Less) Long-Term Portion of Derivative Instrument Liabilities			
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		273,888,025	306,366,765
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		5,931,396	9,676,103
57	Accumulated Deferred Investment Tax Credits (255)	266		
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	2,925,888	2,870,238

60	Other Regulatory Liabilities (254)	278	95,360,910	97,034,399
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		[a]160,437,399	150,803,951
64	Accum. Deferred Income Taxes-Other (283)		[b]17,383,923	17,870,601
65	Total Deferred Credits (lines 56 through 64)		282,039,516	278,255,292
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,507,402,680	1,498,306,428

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Note: Amounts footnoted are based upon FERC-approved rates

			Changes During Year				Adjustments				
							Debits		Credits		
	Account	Balance at Beg of Year	Amounts Debited to Account 410.1	Amounts Credited to Account 411.1	Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account Credited	Amount	Account Debited	Amount	Balance at End of Year
Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Account 282**										
2	Electric	150,803,951	3,929,973	1,607,659			182.3	(2,331,442)	182.3	(155,378)	155,302,329
3	Gas										
4	Other (Define)										
5	Total	150,803,951	3,929,973	1,607,659				(2,331,442)		(155,378)	155,302,329
6											
7	TOTAL Account 282	150,803,951	3,929,973	1,607,659				(2,331,442)		(155,378)	155,302,329
8	**Classification of TOTAL**										
9	Federal Income Tax	150,803,951	3,929,973	1,607,659			182.3	(2,331,442)	182.3	(155,378)	155,302,329
10	State Income Tax										
11	Local Income Tax										

(b) Concept: AccumulatedDeferredIncomeTaxesOther

Note: Amounts footnoted are based upon FERC-approved rates

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
	Account	Balance at Beginning of Year	Amounts Debited to Account 410.1	Amounts Credited to Account 411.1	Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account Credited	Amount	Account Debited	Amount	Balance at End of Year
Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Account 283**										
2	Electric										
3	AFUDC	504							182.3	(163)	341
4	Deferred Costs	7,391,176	27,823	929,754							6,489,245
5	Derivative	0		13,510			219	(13,510)			-
6	Flow Through	4,269,465					182.3	(659,693)	182.3	(41,140)	4,888,018
7	Goodwill	180,962		20,455							160,507
8	Operating Lease Asset	2,823,281		61,073							2,762,208
9	Partnerships	33,705	9,560								43,265
10	Pension	2,602,965		81,464							2,521,501
11	Prepaid Expenses	502,657	428,267	399,187							531,736
12	Reacquired Bond Loss	65,886		38,842							27,045
13											
14	**TOTAL Electric (Total of lines 3 thru 12)**	17,870,601	465,650	1,544,285				(673,203)		(41,303)	17,423,866
15	Gas										
16											
17											
18											
19											
20	TOTAL Gas (Total of lines 15 thru 19)										
21	TOTAL Other										
22	TOTAL (Acct 283) (Enter Total of lines 12, 20, and 21)	17,870,601	465,650	1,544,285				(673,203)		(41,303)	17,423,866
23	**Classification of TOTAL**										
24	Federal Income Tax	17,870,601	465,650	1,544,285				(673,203)		(41,303)	17,423,866
25	State Income Tax										
26	Local Income Tax										

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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 Utility 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	328,620,903	343,909,122			328,620,903	343,909,122				
3	Operating Expenses											
4	Operation Expenses (401)	320	154,731,138	173,044,880			154,731,138	173,044,880				
5	Maintenance Expenses (402)	320	21,128,449	22,463,556			21,128,449	22,463,556				
6	Depreciation Expense (403)	336	50,007,744	48,228,952			50,007,744	48,228,952				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	31,627	30,242			31,627	30,242				
8	Amort. & Depl. of Utility Plant (404-405)	336	1,074,780	1,930,490			1,074,780	1,930,490				
9	Amort. of Utility Plant Acq. Adj. (406)	336	97,406	97,406			97,406	97,406				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)											
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)											
13	(Less) Regulatory Credits (407.4)											
14	Taxes Other Than Income Taxes (408.1)	262	10,788,720	11,399,640			10,788,720	11,399,640				
15	Income Taxes - Federal (409.1)	262	4,050,288	5,919,439			4,050,288	5,919,439				
16	Income Taxes - Other (409.1)	262	257,846	14,395			257,846	14,395				
17	Provision for Deferred Income Taxes (410.1)	234, 272	16,384,623	22,016,859			16,384,623	22,016,859				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	15,667,411	22,948,989			15,667,411	22,948,989				
19	Investment Tax Credit Adj. - Net (411.4)	266										
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)		24,969	24,252			24,969	24,252				
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		242,910,179	262,221,122			242,910,179	262,221,122				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		85,710,724	81,688,000			85,710,724	81,688,000				
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)		629,622	664,398								
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		746,407	799,775								
33	Revenues From Nonutility Operations (417)		34,518	10,954								
34	(Less) Expenses of Nonutility Operations (417.1)		137,700	127,389								
35	Nonoperating Rental Income (418)											
36	Equity in Earnings of Subsidiary Companies (418.1)	119										
37	Interest and Dividend Income (419)		3,536,779	2,160,310								
38	Allowance for Other Funds Used During Construction (419.1)		0	(1,226)								
39	Miscellaneous Nonoperating Income (421)		279,237	107,670								
40	Gain on Disposition of Property (421.1)		1,656,765	89								

41	TOTAL Other Income (Enter Total of lines 31 thru 40)		5,252,814	2,015,031								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)											
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		264,481	296,487								
46	Life Insurance (426.2)											
47	Penalties (426.3)		524	39								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		195,396	136,839								
49	Other Deductions (426.5)		430,244	(338,122)								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		890,645	95,243								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	27,036	24,433								
53	Income Taxes-Federal (409.2)	262	(11,435)	7,499								
54	Income Taxes-Other (409.2)	262										
55	Provision for Deferred Inc. Taxes (410.2)	234, 272										
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272										
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)		15,601	31,932								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		4,346,568	1,887,856								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		20,213,000	20,213,000								
63	Amort. of Debt Disc. and Expense (428)		201,362	201,362								
64	Amortization of Loss on Reaquired Debt (428.1)		184,959	184,959								
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)		16,109,040	8,825,397								
68	Other Interest Expense (431)		(174,412)	68,104								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,235,266	1,165,048								
70	Net Interest Charges (Total of lines 62 thru 69)		35,298,683	28,327,774								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		54,758,609	55,248,082								
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	0									
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		54,758,609	55,248,082								

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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		488,385,201	450,137,120
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1	Dividend to Parent		(17,100,000)	(17,000,001)
15	TOTAL Debits to Retained Earnings (Acct. 439)		(17,100,000)	(17,000,001)
16	Balance Transferred from Income (Account 433 less Account 418.1)		54,758,609	55,248,082
17	Appropriations of Retained Earnings (Acct. 436)			
17.1				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
23.1				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1				
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)		526,043,810	488,385,201
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
39.1				
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)		526,043,810	488,385,201
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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)	54,758,609	55,248,082
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	50,039,371	48,259,194
5	Amortization of (Specify) (footnote details)	1,197,155	2,052,148
5.1	Amortization of utility plant	1,074,780	1,930,490
5.2	Amortization of plant acquisition adjustments	97,406	97,406
5.3	Accretion of Asset Retirement Obligation	24,969	24,252
8	Deferred Income Taxes (Net)	717,212	(932,130)
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	22,706,105	(22,304,973)
11	Net (Increase) Decrease in Inventory	(9,034,287)	(5,997,510)
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	(25,425,619)	12,457,441
14	Net (Increase) Decrease in Other Regulatory Assets	4,464,110	2,874,671
15	Net Increase (Decrease) in Other Regulatory Liabilities		
16	(Less) Allowance for Other Funds Used During Construction		(1,226)
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	6,084,563	4,354,266
18.1	Bad debt expense	388,632	416,933
18.2	Deferred financing cost amortization	386,323	386,320
18.3	Employee benefit plan expense	445,880	569,083
18.4	Gain on retirement of assets	(1,638,707)	0
18.5	Change in regulatory assets and liabilities impacting income statement	1,993,219	2,169,900
18.6	Changes in other current and non-current assets	5,582,220	(936,866)
18.7	Changes in other current and non-current liabilities	(1,073,004)	1,748,896
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	105,507,219	96,012,415
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(60,978,179)	(111,547,216)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	1,235,266	1,165,048
31	Other (provide details in footnote):	1,593,415	(113,059)
31.1	Cost of removal net of salvage	352,291	(42,801)
31.2	Contributions in aid of construction	1,445,161	
31.3	Other investments	(204,037)	(70,258)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(60,620,030)	(112,825,323)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	2,125,003	
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		
53	Other (provide details in footnote):		
53.1			

57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(58,495,027)	(112,825,323)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):	56,950,000	34,539,152
67.1	Net Borrowings from Money Pool	0	15,939,152
67.2	Net Borrowings of Notes Payable to Parent	56,950,000	18,600,000
70	Cash Provided by Outside Sources (Total 61 thru 69)	56,950,000	34,539,152
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	(104,693,401)	(17,000,001)
76.1	Dividend to Parent	(17,100,000)	(17,000,001)
76.2	Net Payments to Money Pool	(87,593,401)	0
78	Net Decrease in Short-Term Debt (c)		
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)	(47,743,401)	17,539,151
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)	(731,209)	726,243
88	Cash and Cash Equivalents at Beginning of Period	731,209	4,966
90	Cash and Cash Equivalents at End of Period		731,209

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Power, Inc., doing business as Black Hills Energy ("South Dakota Electric", the "Company", "we", "us", or "our") is a regulated electric utility serving customers in Montana, South Dakota and Wyoming. We are a wholly-owned subsidiary of Black Hills Corporation ("BHC" or "Parent"), a public registrant listed on the New York Stock Exchange.

Basis of Presentation

The financial statements include the accounts of Black Hills Power, Inc. and also our ownership interests in the assets, liabilities and expenses of our jointly owned facilities (Note 6).

The financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP) and contemplates the realization of assets and the satisfaction of liabilities in the normal course of business. Additionally, these requirements differ from GAAP related to the presentation of certain items discussed below.

The Company is dependent upon financial support from its Parent in order to obtain and renew debt financing. The financial statements have been prepared from the separate records maintained by the Company and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unaffiliated entity. As of December 31, 2023, the Company had $190 million of outstanding short-term Notes payable to Parent. The Company does not have sufficient cash on hand or available liquidity to repay these obligations which are due within one year after the date that the financial statements are issued. In response to this condition, the Company's Parent, has committed to fully support the Company's operating, investing and financing activities to enable the Company to meet its obligations as they become due for at least one year following the date that the financial statements are issued.

Financial Statement Presentation and Basis of Accounting

The financial statements are presented on the basis of the accounting requirements of FERC as set forth in its applicable Uniform System of Accounts and this report differs from GAAP. The significant differences consist of the following:

- The accumulated reserve for estimated removal costs is included in the accumulated provision for depreciation for FERC reporting. For GAAP reporting it is reported as a regulatory liability.
- Deferred financing costs are presented in deferred debits on the balance sheet for FERC reporting. For GAAP reporting, these are presented net within long-term debt.
- Unbilled revenue is presented in Accrued Utility Revenues for FERC reporting and presented in Accounts Receivable for GAAP reporting.
- Accumulated deferred tax assets and liabilities are classified in the balance sheet as gross deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred asset or liability.
- Uncertain tax positions related to temporary differences are classified in the Balance Sheets within the deferred tax accounts in accordance with regulatory treatment, as compared to other noncurrent liabilities for GAAP purposes. In addition, interest related to uncertain tax positions is recognized in interest expense in accordance with regulatory treatment, as compared to income tax expense for GAAP purposes.
- For FERC reporting, regulatory assets and liabilities are classified as noncurrent deferred debits and credits, respectively, while GAAP classifies regulatory assets and liabilities as current and noncurrent.
- Various revenues and expenses are presented as other income and income deductions for the FERC presentation and reported as operating income and expense for the GAAP presentation.
- Only the service cost component of net periodic pension and post-retirement benefit costs can be capitalized for GAAP reporting. Therefore, we record a regulatory asset/liability for GAAP associated with the portion of such costs. However, all cost components of net periodic pension and post-retirement benefit costs are eligible for capitalization under FERC regulations.
- Capital and operating leases are both classified as capital leases on the balance sheet for FERC reporting. For GAAP reporting, these are presented separately.
- Goodwill (plant acquisition adjustments) is included within utility plant for FERC reporting but is presented as other non-current assets for GAAP reporting.

Use of Estimates

The preparation of financial statements in conformity with FERC requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Changes in facts and circumstances or additional information may result in revised estimates and actual results could differ materially from those estimates.

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents. As of December 31, 2023 and 2022, we have no cash equivalents.

Revenue Recognition

Our revenue contracts generally provide for performance obligations that are fulfilled and transfer control to customers over time, represent a series of distinct services that are substantially the same, involve the same pattern of transfer to the customer and provide a right to consideration from our customers in an amount that corresponds directly with the value to the customer for the performance completed to date. Therefore, we recognize revenue in the amount to which we have a right to invoice. Our primary types of revenue contracts are:

- Regulated natural gas and electric utility services tariffs - Our regulated operations provide services to regulated customers under tariff rates, charges, terms and conditions of service, and prices determined by the jurisdictional regulators designated for our service territories. Our regulated services primarily encompass single performance obligations for delivery of commodity electricity and electric transmission services. These service revenues are variable based on quantities delivered, influenced by seasonal business and weather patterns. Tariffs are only permitted to be changed through a rate-setting process involving the state or federal regulatory commissions to establish contractual rates between the utility and its customers. All of our regulated utility sales are subject to regulatory-approved tariffs.
- Power sales agreements - We have long-term wholesale power sales agreements with other load serving entities for the sale of excess power from owned generating units. In addition to these long-term contracts, the Company also sells excess energy to other load-serving entities on a short-term basis. The pricing for all of these arrangements is included in the executed contracts or confirmations, reflecting the standalone selling price, and is variable based on energy delivered.

The majority of our revenue contracts are based on variable quantities delivered; any fixed consideration contracts with an expected duration of one year or more are immaterial to our revenues. Variable consideration constraints in the form of discounts, rebates, credits, price concessions, incentives, performance bonuses, penalties or other similar items are not material for our revenue contracts. We are the principal in our revenue contracts, as we have control over the services prior to those services being transferred to the customer.

Revenue Not in Scope of ASC 606

Other revenues included in the table in Note 4 include revenue accounted for under separate accounting guidance, including alternative revenue programs revenue under ASC 980, Regulated Operations.

Significant Judgments and Estimates

Unbilled Revenue

To the extent that deliveries have occurred but a bill has not been issued, the Company accrues an estimate of the revenue since the latest billing. This estimate is calculated based on several factors including billings through the last billing cycle in a month and prices in effect in our jurisdictions. Each month the estimated unbilled revenue amounts are trued-up and recorded in Accrued Utility Revenues (Account 173) on the accompanying Balance Sheets.

Contract Balances

The nature of our primary revenue contracts provides an unconditional right to consideration upon service delivery; therefore, no customer contract assets or liabilities exist. The unconditional right to consideration is represented by the balance in our Accounts Receivable and is further discussed below.

Accounts Receivable and Allowance for Credit Losses

Accounts receivable are stated at billed amounts, net of allowance for credit losses, and do not bear interest. We maintain an allowance for credit losses which reflects our best estimate of uncollectible trade receivables. We regularly review our trade receivable allowance by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect collectability.

In specific cases where we are aware of a customer's inability or reluctance to pay, we record an allowance for credit losses to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, expected losses, the level of commodity prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible or the time allowed for dispute under the contract has expired.

Changes to Allowance for credit losses (Account 144) for the years ended December 31, were as follows (in thousands):

	Balance at beginning of year	Additions charged to costs and expenses	Recoveries and Other Additions	Write-offs and Other Deductions	Balance at end of year
2023	$ 182	$ 388	$ 180	$ (611)	$ 139
2022	$ 173	$ 417	$ 212	$ (620)	$ 182

Materials, Supplies and Fuel

Materials, supplies and fuel used for construction, operation and maintenance purposes are recorded using the weighted-average cost method.

Debt Discounts and Deferred Financing Costs

Deferred financing costs include loan origination fees, underwriter fees, legal fees and other costs directly attributable to the issuance of debt. Debt discounts and deferred financing costs are amortized over the estimated useful life of the related debt. Unamortized deferred financing costs are presented on the balance sheet within Deferred Debits - Unamortized Debt Expenses (181). Unamortized discounts are presented on the balance sheet within Unamortized Discount on Long-Term Debt-Debit (226). See additional information in Note 13.

Regulatory Accounting

Our regulated operations are subject to cost-of-service regulation and earnings oversight from federal and state regulatory commissions. We account for income and expense items in accordance with accounting standards for regulated operations:

- Certain costs, which would otherwise be charged to expense or other comprehensive income (OCI), are deferred as regulatory assets based on the expected ability to recover the costs in future rates.
- Certain credits, which would otherwise be reflected as income or OCI, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Management continually assesses the probability of future recoveries and obligations associated with regulatory assets and liabilities. Factors such as the current regulatory environment, recently issued rate orders, and historical precedents are considered. As a result, we believe that the accounting prescribed under rate-based regulation remains appropriate and our regulatory assets are probable of recovery in current rates or in future rate proceedings.

If changes in the regulatory environment occur, we may no longer be eligible to apply this accounting treatment, and may be required to eliminate regulatory assets and liabilities from our balance sheet. Such changes could adversely affect our results of operations, financial position or cash flows.

See Note 2 for additional information.

Property, Plant and Equipment

Property, plant and equipment is stated at cost, which includes construction-related direct labor and material costs, indirect construction costs including labor and related costs of departments associated with supporting construction activities, and allowance for funds used during construction (AFUDC). Additions to and significant replacements of property are charged to property, plant and equipment at cost. Ordinary repairs and maintenance of property, except as allowed under rate regulations, are charged to operations as incurred.

We also capitalize interest, when applicable, on undeveloped leasehold costs. At the time of such retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. The amounts capitalized are included in Utility plant on the accompanying Balance Sheets.

We receive contributions in aid of construction (CIACs) from third parties that are generally intended to defray all or a portion of the costs for certain capital projects. Such CIAC costs are recorded as a reduction to Construction work in progress.

The cost of regulated Utility plant retired, or otherwise disposed of in the ordinary course of business, less salvage plus retirement costs, is charged to accumulated provision for depreciation. Retirement or disposal of all other assets result in gains or losses recognized as a component of Other Income. Ordinary repairs and maintenance of property, except as allowed under regulations, are charged to operations as incurred.

Depreciation

Depreciation provisions for property, plant and equipment are generally computed on a straight-line basis based on the applicable estimated service life of the various classes of property. The composite depreciation method is applied to regulated utility property. Depreciation studies are conducted periodically to update composite rates and are approved by the state utility commission and/or the FERC when required.

Depreciation provisions for regulated electric property, plant and equipment are computed on a straight-line basis using an annual composite rate of 2.4% in 2023 and 2.3% in 2022.

AFUDC

Included in the cost of regulated construction projects is AFUDC, when applicable, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a regulated utility project.

Derivatives and Hedging Activities

Derivatives are measured at fair value and recognized as either assets or liabilities on the Balance Sheets, except for derivative contracts that qualify for and are elected under the normal purchase and normal sales exception. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable amount of time, and price is not tied to an unrelated underlying derivative. Normal purchase and sales contracts are recognized when the underlying physical transaction is completed under the accrual basis of accounting. From time to time we utilize risk management contracts including interest rate swaps to fix the interest on variable rate debt or to lock in the Treasury yield component associated with anticipated issuance of senior notes. In August 2002, we entered into a treasury lock, which are interest rate swaps, to hedge $50 million of our First Mortgage Bonds due on August 15, 2032. The treasury lock cash settled on August 8, 2002, the bond pricing date, and resulted in a $1.8 million loss. The treasury lock is designated as a cash flow hedge and the resulting loss is carried in Accumulated other comprehensive loss and is being amortized over the life of the First Mortgage Bonds.

As of December 31, 2023, we had no outstanding derivatives on the Balance Sheet.

Fair Value Measurements

We use the following fair value hierarchy for determining inputs for our financial instruments. Our assets and liabilities for financial instruments are classified and disclosed in one of the following fair value categories:

Level 1 - Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities. Level 1 instruments primarily consist of highly liquid and actively traded financial instruments with quoted pricing information on an ongoing basis.

Level 2 - Pricing inputs include quoted prices for identical or similar assets and liabilities in active markets other than quoted prices in Level 1, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 - Pricing inputs are generally less observable from objective sources. These inputs reflect management's best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable, such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery date of a transaction becomes more observable, such as when the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs. We currently do not have any Level 3 investments.

Additional fair value information is included in Notes 7 and 8.

Income Taxes

We are subject to federal income taxes. We file a federal income tax return with other members of the Parent's consolidated group. For financial statement purposes, federal income taxes are allocated to the individual companies based on amounts calculated on a separate return basis.

The Company uses the asset and liability method in accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements.

We use the deferral method of accounting for investment tax credits as allowed by our rate-regulated jurisdictions. Such a method results in the investment tax credit being amortized as a reduction to income tax expense over the estimated useful lives of the underlying property that gave rise to the credit.

We recognize interest income or interest expense and penalties related to income tax matters in Other interest expense on the Statements of Income.

We have elected to account for transferable clean energy tax credits, including production tax credits and investment tax credits within the provision for income taxes.

We account for uncertainty in income taxes recognized in the financial statements in accordance with the accounting standards for income taxes. The unrecognized tax benefit is classified within deferred tax accounts in accordance with regulatory treatment on the accompanying Balance Sheets.

See Note 9 for additional information.

(2) REGULATORY MATTERS

We had the following regulatory assets and liabilities as follows as of December 31 (in thousands):

	2023	2022
Regulatory assets		
Deferred energy, fuel and transmission cost adjustments [(a)]	$ 29,840	$ 34,304
Deferred taxes on AFUDC [(a)]	3,988	4,185
Employee benefit plans and related deferred taxes [(b)]	17,155	16,794
Deferred taxes on flow through accounting [(a)]	19,100	16,149
Decommissioning costs [(b)]	-	887
Vegetation management [(a)]	-	1,152
Other regulatory assets [(a)]	298	508
Total Other Regulatory Assets (182.3)	$ 70,381	$ 73,979
Regulatory liabilities		
Employee benefit plans and related deferred taxes [(b)]	$ 6,009	$ 5,988
Excess deferred income taxes [(b)]	88,416	90,544
Other regulatory liabilities [(b)]	936	502
Total Other Regulatory Liabilities (254)	$ 95,361	$ 97,034

(a) Recovery/repayment of costs but we are not allowed a rate of return.
(b) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base.

Regulatory assets represent items we expect to recover from customers through probable future increases in rates.

Deferred Energy, Fuel and Transmission Cost Adjustments - Deferred energy, fuel and transmission cost adjustments represent the cost of electricity delivered to our customers that is either higher or lower than the current rates and will be recovered or refunded in future rates. Deferred energy, fuel and energy cost adjustments are recorded and recovered or amortized as approved by the appropriate state commission. We file periodic quarterly, semi-annual and/or annual filings to recover these costs based on the respective cost mechanisms approved by the applicable state utility commissions.

Deferred Taxes on AFUDC - The equity component of AFUDC is considered a permanent difference for tax purposes with the tax benefit being flowed through to customers as prescribed or allowed by regulators. If, based on a regulator's action, it is probable the utility will recover the future increase in taxes payable represented by this flow-through treatment through a rate revenue increase, a regulatory asset is recognized. This regulatory asset is a temporary difference for which a deferred tax liability must be recognized. Accounting standards for income taxes specifically address AFUDC-equity and require a gross-up of such amounts to reflect the revenue requirement associated with a rate-regulated environment.

Employee Benefit Plans and Related Deferred Taxes - In connection with accounting for employee benefit plans, we reflect the unrecognized prior service costs and net actuarial loss associated with our defined benefit pension plans and postretirement benefit plans as regulatory assets rather than in accumulated other comprehensive income. These amounts are recovered as employee benefit costs for pensions and postretirement benefits are paid. In addition, this regulatory asset includes the income tax effect of the adjustment required under accounting for compensation-defined benefit plans, to record the full pension and post-retirement benefit obligations. Such income tax effect has been grossed-up to account for the revenue requirement associated with a rate regulated environment.

Deferred Taxes on Flow-Through Accounting - Under flow-through accounting, the income tax effects of certain items are reflected in our cost of service for the customer in the year in which the tax benefits are realized and result in lower utility rates. A regulatory asset was established to reflect that future increases in income taxes payable will be recovered from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a tax benefit for costs considered currently deductible for tax purposes, but are capitalized for book purposes.

Regulatory liabilities represent items we expect to refund to customers through probable future decreases in rates.

Employee Benefit Plans and Related Deferred Taxes - Employee benefit plans represent the cumulative excess of pension and other postretirement benefit costs recovered in rates over pension expense recorded in accordance with accounting standards for compensation-retirement benefits. In addition, this regulatory liability includes the income tax effect of the adjustment required under accounting for compensation-defined benefit plans, to record the full pension and post-retirement benefit obligations. Such income tax effect has been grossed-up to account for the revenue requirement associated with a rate regulated environment.

Excess Deferred Income Taxes - The revaluation of our deferred tax assets and liabilities due to the passage of the TCJA is recorded as an excess deferred income tax to be refunded to customers primarily using the normalization principles as prescribed in the TCJA. See Note 9 for additional information.

Recent Regulatory Activity

FERC Formula Rate

The annual rate determination process is governed by the FERC formula rate protocols established in the filed FERC joint-access transmission tariff. Effective January 1, 2023, the annual revenue requirement was $32 million and included estimated weighted average capital additions of $50 million for 2022 and 2023 combined.

(3) COMMITMENTS AND CONTINGENCIES

Unconditional Purchase Obligations

We have power purchase agreements with third parties which extend to 2043, to support our capacity and energy needs beyond our power plants' generation. We currently do not have any unconditional purchase obligations required under these power purchase agreements since our current agreements are derived from renewable energy and vary based on weather conditions.

Environmental Matters

We are subject to costs resulting from a number of federal, state and local laws and regulations which affect future planning and existing operations. They can result in increased capital expenditures, operating and other costs as a result of compliance, remediation and monitoring obligations. We may be required to modify, curtail, replace or cease operating certain facilities or operations to comply with statutes, regulations and other requirements of regulatory bodies.

Reclamation Liability

Under our land lease for our Corriedale Wind Farm, we are required to reclaim land where we have placed wind turbines. The reclamation liabilities are recorded at the present value of the estimated future cost to reclaim the land. Our reclamation liability, which is presented on our Balance Sheet within Asset Retirement Obligations (230), was not material to the Company's financial statements.

Legal Proceedings

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in the financial statements to satisfy alleged liabilities are adequate in light of the probable and estimable contingencies. However, there can be no assurance that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed, and to comply with applicable laws and regulations will not exceed the amounts reflected in the financial statements.

In the normal course of business, we enter into agreements that include indemnification in favor of third parties, such as information technology agreements, purchase and sale agreements and lease contracts. We have also agreed to indemnify our directors, officers and employees in accordance with our articles of incorporation, as amended. Certain agreements do not contain any limits on our liability and therefore, it is not possible to estimate our potential liability under these indemnifications. In certain cases, we have recourse against third parties with respect to these indemnities. Further, we maintain insurance policies that may provide coverage against certain claims under these indemnities.

(4) REVENUE

The following table depicts the disaggregation of revenue from contracts with customers by customer type and timing of revenue recognition (in thousands). Sales tax and other similar taxes are excluded from revenues.

	Year ended December 31, 2023	2022
Customer types:		
Retail	$ 214,440	$ 226,477
Wholesale	13,929	15,243
Market-off-system sales	35,648	44,921
Transmission/Other	62,601	57,679
Revenue from contracts with customers	326,618	344,320
Other revenues	282	264
Total Revenues	$ 326,900	$ 344,584
Timing of revenue recognition:		
Services transferred over time	$ 326,618	$ 344,320
Revenue from contracts with customers	$ 326,618	$ 344,320

(5) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment at December 31 consisted of the following (dollars in thousands):

	FERC Accounts	2023	2023 Weighted Average Useful Life (in years)	2022	2022 Weighted Average Useful Life (in years)	Lives (in years) Minimum	Lives (in years) Maximum
Electric plant:							
Production		$ 716,603	45	$ 707,884	45	25	61
Transmission		299,156	51	280,086	51	42	60
Electric distribution		541,257	45	513,602	45	21	62
Plant acquisition adjustment [(a)]		4,870	32	4,870	32	32	32
General		183,024	28	175,544	28	3	40
Operating lease assets		16,512		16,493			
Total plant-in-service	101-106,114	1,761,422		1,698,479			
Construction work-in-progress	107	19,809		48,030			
Total electric plant		1,781,231		1,746,509			
Less accumulated depreciation and amortization	108, 110, 111, 115	(518,023)		(490,911)			
Electric plant net of accumulated depreciation and amortization		$ 1,263,208		$ 1,255,598			

(a) The plant acquisition adjustment, which relates to the acquisition of our ownership interest in Wyodak Plant, is included in rate base and is being recovered with 8 years remaining.

(6) JOINTLY OWNED FACILITIES

Our financial statements include our share of several jointly-owned utility and non-regulated facilities as described below. Our share of the facilities' expenses are reflected in the appropriate categories of operating expenses in the Statements of Income. Each owner of the facility is responsible for financing its investment in the jointly-owned facilities.

Wyodak Plant

We own a 20% interest in the Wyodak Plant, a 402.3 MW mine-mouth coal-fired electric generating station located at the Gillette, Wyoming energy complex. PacifiCorp owns the remaining ownership percentage and operates the Wyodak Plant. We receive our proportionate share of the Wyodak Plant's capacity and are committed to pay our proportionate share of its additions, replacements and operating and maintenance expenses.

Transmission Tie

We jointly operate an electric transmission system, referred to as the Common Use System, with Basin Electric Power Cooperative and Powder River Energy Corporation. Each participant in the Common Use System individually owns assets that are operated together for a single system. The Common Use System provides transmission service over these utilities' combined 230-kilovolt (kV) and limited 69-kV transmission facilities within areas of southwestern South Dakota and northeastern Wyoming. The Common Use System also provides transmission service to our Transmission Tie.

We own a 35% share of a Direct Current Transmission Tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids serving the western and eastern United States, respectively. Basin Electric Power Cooperative owns the remaining ownership percentage. This Transmission Tie allows us to buy and sell energy in the Eastern grid without having to isolate and physically reconnect load or generation between the two transmission grids, thus enhancing the reliability of our system. It accommodates scheduling transactions in both directions simultaneously, provides additional opportunities to sell excess generation or to make economic purchases to serve our native load and contract obligations, and enables us to take advantage of power price differentials between the two grids. The total transfer capacity of the tie is 400 MW, including 200 MW from West to East and 200 MW from East to West. We are committed to pay our proportionate share of the additions and replacements and operating and maintenance expenses of the transmission tie.

Wygen III

We own a 52% interest in the Wygen III generation facility, a 116 MW mine-mouth, coal-fired power plant located at the Gillette, Wyoming energy complex. MDU and the City of Gillette each owns an undivided ownership interest in Wygen III and are obligated to make payments for costs associated with administrative services and their proportionate share of the costs of operating the plant for the life of the facility. We retain responsibility for plant operations.

Cheyenne Prairie Generating Station

Cheyenne Prairie Generating Station (Cheyenne Prairie), a 140 MW natural-gas fired power generation facility, was placed into commercial operations on October 1, 2014. The facility includes one combined-cycle 100 MW unit that we jointly own with Wyoming Electric, our related party operating in the Cheyenne, Wyoming area. We own 58 MW, and Wyoming Electric owns 42 MW of this combined-cycle unit. Cheyenne Prairie also includes one simple-cycle 40 MW combustion turbine that Wyoming Electric wholly owns. Black Hills Service Company (BHSC) is responsible for plant operations. We are committed to pay our proportionate share of the additions, replacements and operating and maintenance expenses. For the years ended December 31, 2023 and 2022, we were allocated net costs of $3.1 million and $2.4 million, respectively, from Wyoming Electric.

Corriedale Wind Farm

Corriedale, a 52.5 MW wind farm near Cheyenne, Wyoming, was placed into commercial operation in November 2020. This wind farm serves as the dedicated wind energy supply to the Renewable Ready program, which is a voluntary renewable energy subscription program for large commercial, industrial and governmental customers in South Dakota and Wyoming. We own 32.5 MW (62%) and Wyoming Electric owns 20 MW (38%) of this wind farm. We are committed to pay our proportionate share of the additions, replacements and operating and maintenance expenses. BHSC is responsible for operations of the wind farm. For the years ended December 31, 2023 and 2022, we allocated net costs of $0.4 million and $0.6 million, respectively, to Wyoming Electric.

As of December 31, 2023, our interests in jointly-owned generating facilities and transmission systems were (in thousands):

	Ownership interest	Plant in Service	Construction Work in Progress	Less Accumulated Depreciation	Plant Net of Accumulated Depreciation
Wyodak Plant	20%	$ 122,318	$ 27	$ (73,426)	$ 48,919
Transmission Tie	35%	$ 24,517	$ 306	$ (7,849)	16,974
Wygen III	52%	$ 145,308	$ 255	$ (32,159)	113,404
Cheyenne Prairie	58%	$ 117,695	$ 621	$ (22,451)	95,865
Corriedale Wind Farm	62%	$ 52,768	$ -	$ (6,616)	46,152

(7) FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements

Pension and Postretirement Plan Assets

A discussion of the fair value of our Pension and Postretirement Plan assets is included in Note 8.

Other fair value measures

The carrying amount of cash, Money pool notes payable and Notes payable to Parent approximate fair value due to their liquid or short-term nature. Cash is classified in Level 1 in the fair value hierarchy. Money pool notes payable and Notes payable to Parent are not traded on an exchange and are classified in Level 2 in the fair value hierarchy. Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy.

(8) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

BHC sponsors a 401(k) retirement savings plan (the 401(k) Plan). Participants in the 401(k) Plan may elect to invest a portion of their eligible compensation to the 401(k) Plan up to the maximum amounts established by the IRS. The 401(k) Plan provides employees the opportunity to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis.

The 401(k) Plan provides a Company matching contribution for all eligible participants. Certain eligible participants who are not currently accruing a benefit in the Pension Plan also receive a Company retirement contribution based on the participant's age and years of service. Vesting of all Company and matching contributions occurs at 20% per year with 100% vesting when the participant has 5 years of service with the Company.

Defined Benefit Pension Plan (Pension Plan)

We have one defined benefit pension plan ("Pension Plan") covering certain eligible employees. The benefits for the Pension Plan are based on years of service and calculations of average earnings during a specific time period prior to retirement. The Pension Plan is closed to new employees and frozen for certain employees who did not meet age and service based criteria.

The Pension Plan assets are held in a Master Trust. BHC's Board of Directors has approved the Pension Plan's investment policy. The objective of the investment policy is to manage assets in such a way that will allow the eventual settlement of our obligations to the Pension Plan's beneficiaries. To meet this objective, our pension assets are managed by an outside adviser using a portfolio strategy that will provide liquidity to meet the Pension Plan's benefit payment obligations. The Pension Plan's assets consist primarily of equity, fixed income and hedged investments.

The expected rate of return on the Pension Plan assets is determined by reviewing the historical and expected returns of both equity and fixed income markets, taking into account asset allocation, the correlation between asset class returns, and the mix of active and passive investments. The Pension Plan utilizes a dynamic asset allocation where the target allocation range to return-seeking and liability-hedging assets is determined based on the funded status of the Plan. As of December 31, 2023, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 20% to 28% return-seeking assets and 72% to 80% liability-hedging assets.

Our Pension Plan is funded in compliance with the federal government's funding requirements.

Pension Plan Assets

The percentages of total plan asset by investment category of our Pension Plan assets at December 31 were as follows:

	2023	2022
Return-seeking Assets		
Equity	14%	14%
Real estate	5%	7%
Hedge funds	3%	3%
Fixed income	2%	2%
Total	24%	26%
Liability-hedging Assets		
Fixed income	74%	72%
Cash	2%	2%
Total	76%	74%
Total assets	100%	100%

Supplemental Non-qualified Defined Benefit Plans

We have various supplemental retirement plans for key executives of the Company. The plans are non-qualified defined benefit and defined contribution plans (Supplemental Plans). The Supplemental Plans are subject to various vesting schedules and are funded on a cash basis as benefits are paid.

Non-pension Defined Benefit Postretirement Healthcare Plan

BHC sponsors a retiree healthcare plan (Healthcare Plan) for employees who meet certain age and service requirements at retirement. Healthcare Plan benefits are subject to premiums, deductibles, co-payment provisions and other limitations. Pre-65 retirees receive their retiree medical benefits through the Black Hills self-insured retiree medical plans. Healthcare coverage for Medicare-eligible BHP retirees is provided through an individual market healthcare exchange. The Healthcare Plan has no assets. We fund on a cash basis as benefits are paid.

Plan Contributions

Contributions to the Pension Plan are cash contributions made directly to the Master Trust. Healthcare benefits include company and participant paid premiums.

Contributions for the years ended December 31 were as follows (in thousands):

	2023	2022
Defined Contribution Plans		
Company Retirement Contribution	$ 1,066	$ 1,051
Matching Contributions	$ 1,357	$ 1,346
Defined Benefit Plans		
Defined Benefit Pension Plan	$ -	$ -
Non-Pension Defined Benefit Postretirement Healthcare Plan	$ 345	$ 154
Supplemental Non-qualified Defined Benefit Plan	$ 321	$ 321

We do not have any required 2024 contributions, however, we currently expect to contribute $0.3 million to our Pension Plan.

Fair Value Measurements

The following tables set forth, by level within the fair value hierarchy, the assets that were accounted for at fair value on a recurring basis (in thousands):

Pension Plan				**December 31, 2023**		
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV [(a)]	Total Fair Value
Common Collective Trust - Cash and Cash Equivalents	$ -	$ 881	$ -	$ 881	$ -	$ 881
Common Collective Trust - Equity	-	5,660	-	5,660	-	5,660
Common Collective Trust - Fixed Income	-	31,085	-	31,085	-	31,085
Common Collective Trust - Real Estate	-	-	-	-	2,177	2,177
Hedge Funds	-	-	-	-	1,074	1,074
Total investments measured at fair value	$ -	$ 37,626	$ -	$ 37,626	$ 3,251	$ 40,877

Pension Plan				**December 31, 2022**		
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV [(a)]	Total Fair Value
Common Collective Trust - Cash and Cash Equivalents	$ -	$ 825	$ -	$ 825	$ -	$ 825
Common Collective Trust - Equity	-	5,838	-	5,838	-	5,838
Common Collective Trust - Fixed Income	-	31,336	-	31,336	-	31,336
Common Collective Trust - Real Estate	-	-	-	-	2,793	2,793
Hedge Funds	-	-	-	-	1,047	1,047
Total investments measured at fair value	$ -	$ 37,999	$ -	$ 37,999	$ 3,840	$ 41,839

(a) Certain investments that are measured at fair value using Net Asset Value "NAV" per share (or its equivalent) for practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in these tables for these investments are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the reconciliation of changes in the plan's benefit obligations and fair value of plan assets above.

Additional information about assets of the Pension Plan, including methods and assumptions used to estimate the fair value of these assets, is as follows:

Common Collective Trust Funds: These funds are valued based upon the redemption price of units held by the Pension Plan, which is based on the current fair value of the common collective trust funds' underlying assets. Unit values are determined by the financial institution sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation dates. The Pension Plan's investments in common collective trust funds, with the exception of shares of the common collective trust-real estate are categorized as Level 2.

The following investments are measured at NAV and are not classified in the fair value hierarchy, in accordance with accounting guidance.

Common Collective Trust-Real Estate Funds: These funds are valued based on various factors of the underlying real estate properties, including market rent, market rent growth, occupancy levels, etc. As part of the trustee's valuation process, properties are externally appraised generally on an annual basis. The appraisals are conducted by reputable independent appraisal firms and signed by appraisers that are members of the Appraisal Institute, with professional designation of Member, Appraisal Institute. All external appraisals are performed in accordance with the Uniform Standards of Professional Appraisal Practices. We receive monthly statements from the trustee, along with the annual schedule of investments and rely on these reports for pricing the units of the fund.

Hedge Funds: These funds represent investments in other investment funds that seek a return utilizing a number of diverse investment strategies. The strategies, when combined, aim to reduce volatility and risk while attempting to deliver positive returns under all market conditions. Amounts are reported on a one-month lag. The fair value of hedge funds is determined using net asset value per share based on the fair value of the hedge fund's underlying investments. 10% of the shares may be redeemed at the end of each month with a 15-day notice and full redemptions are available at the end of each quarter with 60-day notice and is limited to a percentage of the total net assets value of the fund. The net asset values are based on the fair value of each fund's underlying investments. There are no unfunded commitments related to these hedge funds.

Components of Net Periodic Expense

The following table provides a reconciliation of components of the net periodic expense (in thousands):

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
As of December 31,	2023	2022	2023	2022	2023	2022
Service cost	$ 144	$ 255	$ -	$ -	$ 113	$ 150
Interest cost	2,228	1,379	105	57	155	89
Expected return on assets	(2,408)	(2,402)	-	-	-	-
Amortization of prior service cost (credits)	(16)	(16)	-	-	(173)	(309)
Amortization of loss (gain)	-	-	-	-	(37)	(14)
Recognized net actuarial loss (gain)	440	1,437	14	39	-	-
Net periodic expense	$ 388	$ 653	$ 119	$ 96	$ 58	$ (84)

Actuarial gains and losses are amortized using a straight-line method over the average remaining service period of active plan participants or over the average remaining lifetime of the remaining plan participants if the plan is viewed as "all or almost all" inactive participants.

Other Plan Information

The following tables provide a reconciliation of the employee benefit plan obligations, fair value of assets, amounts recognized in the Balance Sheets, accumulated benefit obligation and elements of AOCI (in thousands):

	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Plans	Non-pension Defined Benefit Postretirement Healthcare Plan	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Plans	Non-pension Defined Benefit Postretirement Healthcare Plan
	2023			2022		

Accumulated benefit obligation at December 31,	$ 45,307	$ 2,073	$ 3,221	$ 45,341	$ 2,238	$ 3,305
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 45,802	$ 2,237	$ 3,305	$ 61,215	$ 2,837	$ 4,448
Service cost	144	-	113	255	-	150
Interest cost	2,228	105	155	1,379	58	89
Actuarial (gain) loss	2,842	52	(128)	(11,729)	(336)	(848)
Benefits paid	(5,378)	(321)	(345)	(5,318)	(321)	(690)
Plan participants transfer to affiliate	-	-	(1)	-	-	2
Plan participants' contributions	-	-	122	-	-	154
Projected benefit obligation at end of year	45,638	2,073	3,221	45,802	2,238	3,305
Change in fair value of plan assets:						
Fair value of plan assets at beginning of year	41,839	-	-	59,669	-	-
Investment income (loss)	4,444	-	-	(12,515)	-	-
Benefits paid	(5,378)	(321)	(345)	(5,318)	(321)	(690)
Participant contributions	-	-	122	-	-	154
Employer contributions	-	321	223	-	321	536
Plan participants transfer to affiliate	-	-	-	3	-	-
Fair value of plan assets at end of year	40,905	-	-	41,839	-	-
Funded status - deficiency	$ 4,733	$ 2,073	$ 3,221	$ 3,963	$ 2,238	$ 3,305
Amounts recognized on our Balance Sheets as of December 31:						
Other Regulatory Assets (182.3)	$ 16,740	$ -	$ -	$ 16,358	$ -	$ -
Miscellaneous Current and Accrued Liabilities (242)	-	319	432	-	319	502
Accumulated Provision for Pensions and Benefits (228.3)	4,733	1,754	2,789	3,963	1,918	2,803
Other Regulatory Liabilities (254)	-	-	1,559	-	-	1,640
Amounts recognized in AOCI, net of tax as of December 31:						
Net (gain) loss	$ -	$ 397	$ -	$ -	$ 368	$ -
Total amounts included in AOCI, after-tax not yet recognized as components of net periodic expense	$ -	$ 397	$ -	$ -	$ 368	$ -

In 2012, we froze our Pension Plan and closed it to new participants. Since then, we have implemented various de-risking strategies including lump sum buyouts, the purchase of annuities and the reduction of return-seeking assets over time to a more liability-hedged portfolio. As a result, capital markets volatility had a limited impact to our unfunded status.

Assumptions

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plan	
	2023	2022	2023	2022	2023	2022
Weighted-average assumptions used to determine benefit obligations:						
Discount rate	4.99%	5.17%	4.91%	5.11%	4.97%	5.14%
Rate of increase in compensation levels	3.04%	3.06%	N/A	N/A	N/A	N/A
Weighted-average assumptions used to determine net periodic benefit cost for plan year:						
Discount rate [(a)]	5.17%	2.88%	5.11%	2.70%	5.14%	2.79%
Expected long-term rate of return on assets [(b)]	6.00%	4.25%	N/A	N/A	3.10%	1.70%
Rate of increase in compensation levels	3.06%	3.08%	N/A	N/A	N/A	N/A

(a) The estimated discount rate for the Defined Benefit Pension Plan is 5.0% for the calculation of the 2024 net periodic pension costs.
(b) The expected rate of return on Defined Benefit Pension Plan plan assets is 6.0% for the calculation of the 2024 net periodic pension costs.

The healthcare benefit obligation was determined at December 31 as follows:

	2023	2022
Trend Rate - Medical		
Pre-65 for next year - All plans	6.69%	7.00%
Pre-65 Ultimate trend rate	4.50%	4.50%
Trend Year	2034	2031
Post-65 for next year - all plans	5.81%	6.00%
Post-65 Ultimate trend rate	4.50%	4.50%
Trend Year	2034	2031

Estimated Future Benefit Payments

The following benefit payments, which reflect future service, are expected to be paid (in thousands):

	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Plans	Non-pension Defined Postretirement Healthcare Plan
2024	$ 3,649	$ 319	$ 432
2025	$ 3,646	$ 288	$ 397
2026	$ 3,642	$ 248	$ 386
2027	$ 3,630	$ 216	$ 390
2028	$ 3,576	$ 209	$ 357
2029-2033	$ 17,202	$ 877	$ 1,415

(9) INCOME TAXES

Income Tax Expense

Income tax expense for the years ended December 31 was as follows (in thousands):

	2023	2022
Current income tax expense (Accounts 409.1 and 409.2)	$ 4,297	$ 5,941
Deferred income tax expense (benefit) (Accounts 410.1 and 411.1)	717	(932)
Total income tax expense	$ 5,014	$ 5,009

Effective Tax Rates

The effective tax rate differs from the federal statutory rate for the years ended December 31, as follows:

	2023	2022
Federal statutory rate	21.0%	21.0%
Amortization of excess deferred income taxes [(a)]	(2.9)	(3.8)
Flow-through adjustments [(b)]	(2.6)	(2.0)
Tax credits	(6.5)	(7.0)
Uncertain tax benefits	-	(0.1)
Other	(0.6)	0.2
Effective tax rate	8.4%	8.3%

(a) Primarily TCJA - see Tax Reform section below for further details.
(b) Flow-through adjustments related primarily to an accounting method change for tax purposes that allows us to take a current tax deduction for repair costs. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and we flowed the tax benefit through to tax expense.

Deferred Tax Assets and Liabilities

The temporary differences, which gave rise to the net deferred tax liability, at December 31 were as follows (in thousands):

	2023	2022
Deferred tax assets:		
Regulatory liabilities	$ 22,604	$ 22,947
Employee benefit plans	1,676	1,679
Accumulated depreciation and other plant-related differences	1,559	2,264
Credit carryovers	15,109	11,189
Federal NOL	3,219	2,741
Other	4,336	4,020
Total deferred tax assets (Account 190)	48,503	44,840
Deferred tax liabilities:		
Regulatory assets	(8,071)	(7,645)
Accelerated depreciation and other plant related differences	(157,120)	(147,362)
Employee benefit plans	(3,053)	(3,106)
Deferred energy costs	(6,489)	(7,391)
Other	(3,088)	(3,171)
Total deferred tax liabilities (Accounts 282 and 283)	(177,821)	(168,675)
Net deferred tax assets (liabilities)	$ (129,318)	$ (123,835)

Net Operating Loss and Tax Credit Carryforwards

At December 31, 2023, we have federal NOL and tax credit carryforwards that will expire at various dates as follows (in thousands):

	Amounts	Expiration Dates
Federal NOL carryforward	$ 15,330	2034
Federal tax credit carryforward	$ 15,109	2029-2043

Unrecognized Tax Benefits

The following table reconciles the total amounts of unrecognized tax benefits, without interest, included in deferred tax accounts in accordance with regulatory treatment on the accompanying Balance Sheet (in thousands):

	2023	2022
Unrecognized tax benefits at January 1	$ 950	$ 872
Additions for prior year tax positions	-	(42)
Additions for current year tax positions	153	120
Reductions for prior year tax positions	(12)	-
Unrecognized tax benefits at December 31	$ 1,091	$ 950

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is $1.1 million.

It is our continuing practice to recognize interest and penalties related to income tax matters in Other interest expense. During the years ended December 31, 2023 and 2022, the interest expense recognized was not material to our financial results.

We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of any audits or the expiration of statutes of limitations on or before December 31, 2024.

Tax Reform

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA reduced the U.S. federal corporate tax rate from 35% to 21%. As such, the Company has remeasured the deferred income taxes at the 21% federal tax rate as of December 31, 2017.

The regulatory liability for excess deferred income taxes that is considered protected and unprotected as of December 31 is reflected below (in millions):

	2023	2022
Jurisdiction		
Protected		
FERC	$ 13.1	$ 13.4
State	65.0	66.6
Total Protected	$ 78.1	$ 80.0
Unprotected		
FERC	$ 1.9	$ 1.9
State	8.4	8.6
Total Unprotected	$ 10.3	$ 10.5
Total excess deferred income tax liabilities (Account 254)	$ 88.4	$ 90.5

In 2018, we received an order from the South Dakota Public Utilities Commission approving a settlement stipulation regarding how customer rates should be reduced for excess deferred income taxes. The settlement stipulation required (i) a refund of protected and non-protected plant asset related excess deferred income taxes pursuant to the average rate assumption method ("ARAM") and (ii) a refund in 2019 of all non-protected excess deferred income taxes not related to plant assets. We have made a compliance filing under FERC Order No. 864 to demonstrate this approach complies with generally applicable FERC requirements.

The adjustments to the regulatory liability (account 254) for the year ended December 31, 2023, the estimated amortization period based on regulatory orders, and the accounts where the adjustments and amortization were reported are reflected below (in millions):

		Accounts							
Jurisdiction	December 31, 2022	182.3	190	254 Other	282	283	411	December 31, 2023	Amortization Period
Protected									
FERC	$ 13.4	$ -	$ (0.1)	$ -	$ -	$ -	$ (0.2)	$ 13.1	(a)
State	66.6	-	(0.4)	-	-	-	(1.2)	65.0	(a)
Total Protected	$ 80.0	$ -	$ (0.5)	$ -	$ -	$ -	$ (1.4)	$ 78.1	

Unprotected									
FERC	$ 1.9	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.9	(a)
State	8.6	-	(0.1)	-	-	-	(0.1)	8.4	(a)
Total Unprotected	$ 10.5	$ -	$ (0.1)	$ -	$ -	$ -	$ (0.1)	$ 10.3	
Total excess deferred income tax liabilities (Account 254)	$ 90.5	$ -	$ (0.6)	$ -	$ -	$ -	$ (1.5)	$ 88.4	

(a) The weighted average amortization period was estimated at 55-75 years under ARAM.

(10) LEASES

We have a ground lease for the Wygen III generating facility with Wyodak Resources Development Corporation (WRDC), a related party coal mine which is a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings. We also have communication tower site and operation center facility leases with third parties. Our leases have remaining terms ranging from one year to 26 years, including options to extend that are reasonably certain to be exercised.

Most of our leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is generally calculated using our borrowing rate at lease inception.

The components of lease expense for the years ended December 31, 2023 and 2022 were not material to the financial statements.

Supplemental balance sheet information related to leases was as follows (in thousands):

	Balance Sheet Location	As of December 31, 2023	As of December 31, 2022
Assets:			
Operating leases	Utility Plant (101-106,114)	$ 16,512	$ 16,493
Operating leases	(Less) Accum. Prov. For Depr. Amort. Depl. (108, 110, 111,115)	(3,361)	(3,058)
Total lease assets		$ 13,151	$ 13,435
Liabilities:			
Operating leases	Obligations Under Capital Leases - Noncurrent (227)	$ 12,826	$ 13,129
Operating leases	Obligations Under Capital Leases - Current (243)	347	327
Total lease liabilities		$ 13,173	$ 13,456

As of December 31, 2023, scheduled maturities of operating lease liabilities for future years were as follows (in thousands):

	Total
2024	$ 914
2025	860
2026	860
2027	846
2028	846
Thereafter	17,720
Total lease payments	$ 22,046
Less imputed interest	(8,873)
Present value of lease liabilities	$ 13,173

(11) RELATED-PARTY TRANSACTIONS

Dividends to Parent

For the years ended December 31, 2023 and 2022, we paid dividends of $17.1 million and $17.0 million, respectively, to our Parent.

Money Pool Notes Payable

We participate in the Utility Money Pool Agreement (the Agreement). Under the Agreement, we may borrow from the pool; however, the Agreement restricts the pool from loaning funds to BHC or to any of BHC's non-utility subsidiaries. The Agreement does not restrict us from paying dividends to BHC. Borrowings under the Agreement bear interest at the weighted average daily cost of BHC's external borrowings as defined under the Agreement, or if there are no external funds outstanding on that date, then the rate will be the daily one-month Secured Overnight Financing Rate (SOFR) plus 1.125%. The cost of borrowing under the Utility Money Pool was 6.48% at December 31, 2023.

We had the following balances with the Utility Money Pool as of December 31 (in thousands):

	2023	2022
Money pool notes receivable - Notes Receivable from Associated Companies (145)	$ 13,581	$ -
Money pool interest receivable - Notes Receivable from Associated Companies (145)	$ 42	$ -
Money pool notes payable - Notes Payable to Associated Companies (233)	$ -	$ 73,970
Money pool interest payable - Notes Payable to Associated Companies (233)	$ -	$ 308

Net interest expense relating to the Utility Money Pool for the years ended December 31, was as follows (in thousands):

	2023	2022
Money pool interest income (Account 419)	$ 2,408	$ 1,105
Money pool interest expense (Account 430)	$ 5,150	$ 2,440

Notes payable to Parent

Notes payable to Parent represent the Company's assigned debt from its Parent in support of their capital and accrue interest at a rate that reflects the weighted-average rate of the assigned debt instruments.

Affiliate notes payables as of December 31 (in thousands):

	2023	2022
Notes payable to Parent - Notes Payable to Associated Companies (233)	$ 189,950	$ 133,000
Interest payable on borrowings from associated companies (233)	$ 702	$ 745

Interest expense relating to our Notes Payable to Parent for the year ended December 31, was as follows (in thousands):

	2023	2022
Notes payable to Parent interest expense - Interest on Debt to Assoc. Companies (430)	$ 6,441	$ 4,667

Interest Expense Allocation from Parent

BHC provides daily liquidity and cash management on behalf of all its subsidiaries. For the years ended December 31, 2023 and 2022, we were allocated $4.8 million and $2.0 million, respectively, of interest expense from BHC.

Tax Sharing Agreement

Our Parent, BHC files consolidated federal and state income tax returns. We have a tax sharing agreement with BHC for the allocation of consolidated tax liabilities and benefits. Income taxes recorded represent amounts we would incur as a separate C-Corporation. During the year ended December 31, 2023, we received $5.2 million of net proceeds from BHC due to our tax sharing agreement. During the year ended December 31, 2022, we received $16.9 million from BHC due to our tax sharing agreement. As of December 31, 2023, we did not have an income tax receivable or payable from BHC related to our tax sharing agreement. As of December 31, 2022, we had a $9.5 million income tax receivable to BHC related to our tax sharing agreement.

Gillette Energy Complex Shared Facilities Agreement

We have a shared facilities agreement with Wyoming Electric and Black Hills Wyoming whereby certain assets owned by one or more of the entities at the Gillette Energy Complex in Gillette, Wyoming may be used to support the operations of one or more of the other entities. Under the agreement, each entity is charged a fee for the use of shared assets and is responsible for a share of operations and maintenance costs associated with the shared assets. South Dakota Electric has been appointed as Operator of the complex and is responsible for operating, maintaining and managing the shared assets, as well as administering the agreement. For the years ended December 31, 2023 and 2022, South Dakota Electric allocated net costs of $4.8 million and $4.7 million, respectively, to affiliated entities.

Other Related-Party Agreements

We have the following agreements with affiliated entities:

- A Generation Dispatch and Energy Management Agreement with Wyoming Electric which requires us to purchase all of Wyoming Electric's excess energy. Under this same agreement, Wyoming Electric can also purchase off-system energy from us for the purpose of displacing some, or all, of the available energy from a higher-cost resource.
- As part of the Gillette Energy Complex shared facilities agreement referenced above, we recognize rent revenue from affiliates for their use of the shared assets we own. Additionally, we recognize rent expense to affiliates for our use of the shared assets they own.
- Black Hills Power and Black Hills Service Company (BHSC) are parties to a shared facilities agreement, whereby BHSC is charged for the use of the Horizon Point facility that is owned by Black Hills Power and BHSC provides certain operations and maintenance services at the facility.
- All-in requirements agreements with Wyodak Resources Development Corporation (WRDC), a related party coal mine which is a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, for the purchase of coal for use at Neil Simpson II, Wyodak Plant and Wygen III.
- An intercompany agreement with Wyoming Electric to purchase 50% of the output they receive under a separate PPA with Happy Jack Wind Farm, LLC. Their agreement expires in September 2028 and provides up to 30 MW of wind energy from the wind farm located near Cheyenne, Wyoming.
- An intercompany agreement with Wyoming Electric to purchase 67% of the output they receive under a separate PPA with Silver Sage Windpower, LLC. Their agreement expires September 2029 and provides up to 30 MW of wind energy from the wind farm located near Cheyenne, Wyoming.
- A gas transportation service agreement with Wyoming Gas in connection with gas supply for Cheyenne Prairie. The agreement is for a term of 40 years, in which Wyoming Electric and South Dakota Electric pay a monthly service and facility fee (based on each entity's ownership interest in Cheyenne Prairie) for firm and interruptible gas transportation.
- A Wygen III Ground Lease with WRDC mine expiring in 2050 with three automatic renewal terms of 20 years each.
- Spare turbine use agreements with Black Hills Colorado IPP and Wyoming Electric which allow for the use of spare combustion turbine generators owned by South Dakota Electric, Wyoming Electric and Black Hills Colorado IPP to support operations at the Cheyenne Prairie Generating Station.
- A service agreement with BHSC, whereby BHSC charges us, at cost, for various direct and indirect services provided to us. Pursuant to the BHSC Cost Allocation Manual, indirect service cost allocations are determined in accordance with the Public Utility Holding Company Act of 2005.

We had the following related-party transactions for the years ended December 31 within the accompanying Statements of Income (in thousands):

	2023	2022
Operating Revenues:		
Excess energy sold to Wyoming Electric	$ 41	$ 1,781
Rent revenue from affiliates under Gillette energy complex shared facilities agreement	2,711	2,472
Rent revenue from BHSC under Horizon Point shared facilities agreement	11,087	11,469
Spare turbine agreement with Wyoming Electric	1,747	1,136
Operating Expenses:		
Purchases from WRDC	$ 18,993	$ 17,130
Purchases of excess energy from Wyoming Electric	961	4,783
Purchase of renewable wind energy from Wyoming Electric - Happy Jack	1,528	1,834
Purchase of renewable wind energy from Wyoming Electric - Silver Sage	3,488	3,768
Gas transportation service agreement with Wyoming Gas	267	272
Rent expense to affiliates under Gillette energy complex shared facility agreement	416	427
Wygen III ground lease with WRDC	1,163	1,079
Spare turbine agreement with Black Hills Colorado IPP and Wyoming Electric	786	558
Direct services and fees from BHSC	12,949	13,957
Indirect services and fees from BHSC	45,578	43,774

(12) SUPPLEMENTAL CASH FLOW INFORMATION

Years ended December 31, (in thousands)	2023	2022
Cash (paid) refunded during the period for:		
Interest (net of amounts capitalized)	$ (32,894)	$ (26,684)
Income taxes	5,200	(16,897)
Non-cash investing and financing activities:		
Accrued property, plant and equipment purchases at December 31	$ 6,780	$ 8,606

(13) LONG-TERM DEBT

Long-term debt outstanding at December 31 was as follows (in thousands):

			Balance Outstanding	
	Due Date	Interest Rate at December 31, 2023	December 31, 2023	December 31, 2022
First Mortgage bonds due 2032	August 15, 2032	7.23%	$ 75,000	$ 75,000
First Mortgage bonds due 2039	November 1, 2039	6.13%	180,000	180,000
First Mortgage bonds due 2044	October 20, 2044	4.43%	85,000	85,000
Total Bonds (221)			$ 340,000	$ 340,000
Unamortized Debt Expenses (181)			1,985	2,117
Unamortized Discount on Long-Term Debt (226)			66	70

Long-term Debt Maturities

Scheduled maturities of our outstanding long-term debt (excluding unamortized discounts and unamortized deferred financing costs) are as follows (in thousands):

2024	$ -
2025	$ -
2026	$ -
2027	$ -

2028	$	-
Thereafter	$	340,000

Debt Covenants

Substantially all of our property is subject to the lien of the indenture securing our first mortgage bonds. First mortgage bonds may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures. We were in compliance with our debt covenants at December 31, 2023.

(14) SUBSEQUENT EVENTS

We have evaluated subsequent events through April 4, 2024, which is the date the financial statements were available to be issued, and have determined there were no subsequent events that have occurred through that date that have not already been reflected in the financial statements and/or disclosed in the notes.

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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		(663,187)			(465,870)		(1,129,057)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income		30,425			50,822		81,247		
3	Preceding Quarter/Year to Date Changes in Fair Value		265,274					265,274		
4	Total (lines 2 and 3)		295,699			50,822		346,521	55,248,082	55,594,603
5	Balance of Account 219 at End of Preceding Quarter/Year		(367,488)			(415,048)		(782,536)		
6	Balance of Account 219 at Beginning of Current Year		(367,488)			(415,048)		(782,536)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income		11,393			50,823		62,216		
8	Current Quarter/Year to Date Changes in Fair Value		(41,154)			0		(41,154)		
9	Total (lines 7 and 8)		(29,761)			50,823		21,062	54,758,609	54,779,671
10	Balance of Account 219 at End of Current Quarter/Year		(397,249)			(364,225)		(761,474)		

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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)	1,719,087,122	1,684,940,403		[b]34,146,719			
4	Property Under Capital Leases	16,511,625	[a]16,511,625					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	25,380,200	25,380,200					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	1,760,978,947	1,726,832,228		34,146,719			
9	Leased to Others							
10	Held for Future Use	2,155,556	2,155,556					
11	Construction Work in Progress	19,809,320	19,809,320					
12	Acquisition Adjustments	4,870,309	4,870,309					
13	Total Utility Plant (8 thru 12)	1,787,814,132	1,753,667,413		34,146,719			
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	518,023,276	506,707,401		11,315,875			
15	Net Utility Plant (13 less 14)	1,269,790,856	1,246,960,012		22,830,844			
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	510,458,857	499,142,982		11,315,875			
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	3,361,022	3,361,022					
22	Total in Service (18 thru 21)	513,819,879	502,504,004		11,315,875			
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	4,203,397	4,203,397					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	518,023,276	506,707,401		11,315,875			

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases

Amounts represents operating lease right of use assets in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.

(b) Concept: UtilityPlantInServiceClassified

Amounts in column (e) represent allocated property and related accumulated provision for depreciation from Black Hills Service Company.

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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						
4	(303) Miscellaneous Intangible Plant						
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)						
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	230,796					230,796
9	(311) Structures and Improvements	53,793,502	2,370,041	201,317		(81,443)	55,880,783
10	(312) Boiler Plant Equipment	250,488,016	12,662,964	4,222,379		(1,061,551)	257,867,050
11	(313) Engines and Engine-Driven Generators	597,362	1,462				598,824
12	(314) Turbogenerator Units	124,487,768	568,648	588,532		77,125	124,545,009
13	(315) Accessory Electric Equipment	20,273,983	178,361	155,976			20,296,368
14	(316) Misc. Power Plant Equipment	3,252,070	281,891	117,861			3,416,100
15	(317) Asset Retirement Costs for Steam Production						
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	453,123,497	16,063,367	5,286,065		(1,065,869)	462,834,930
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						
28	(331) Structures and Improvements						
29	(332) Reservoirs, Dams, and Waterways						
30	(333) Water Wheels, Turbines, and Generators						
31	(334) Accessory Electric Equipment						
32	(335) Misc. Power Plant Equipment						
33	(336) Roads, Railroads, and Bridges						
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)						
36	D. Other Production Plant						
37	(340) Land and Land Rights	2,365,975		486,296			1,879,679
38	(341) Structures and Improvements	11,319,902	364,520	44,442			11,639,980
39	(342) Fuel Holders, Products, and Accessories	6,141,423	398,474	45,372		(4,926)	6,489,599
40	(343) Prime Movers						
41	(344) Generators	215,159,282	648,683	3,522,470		2,286,512	214,572,007
42	(345) Accessory Electric Equipment	22,067,617	714,723	85,937		(411,816)	22,284,587
43	(346) Misc. Power Plant Equipment	299,345					299,345
44	(347) Asset Retirement Costs for Other Production	756,044					756,044
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	258,109,588	2,126,400	4,184,517		1,869,770	257,921,241
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	711,233,085	18,189,767	9,470,582		803,901	720,756,171
47	3. Transmission Plant						
48	(350) Land and Land Rights	10,648,602	241,432				10,890,034
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	2,018,862	44,863			(29,005)	2,034,720

50	(353) Station Equipment	70,632,083	5,832,760	87,820		(86,744)	76,290,279
51	(354) Towers and Fixtures	864,826					864,826
52	(355) Poles and Fixtures	114,900,098	1,844,258	2,459,182		1,009,636	115,294,810
53	(356) Overhead Conductors and Devices	78,715,664	16,134,831	2,480,719		975,067	93,344,843
54	(357) Underground Conduit						
55	(358) Underground Conductors and Devices						
56	(359) Roads and Trails	6,920					6,920
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	277,787,055	24,098,144	5,027,721		1,868,954	298,726,432
59	4. Distribution Plant						
60	(360) Land and Land Rights	2,897,523	290,174				3,187,697
61	(361) Structures and Improvements	2,470,828	(133,995)	8,100		4,810	2,333,543
62	(362) Station Equipment	115,150,396	499,139	938,980		453,232	115,163,787
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	114,254,889	5,839,135	777,629	(33,721)	(191,830)	119,090,844
65	(365) Overhead Conductors and Devices	69,299,461	(456,735)	455,790	(49,413)	72,705	68,410,228
66	(366) Underground Conduit	20,883,585	4,004,549	163,551	(23,816)	47,442	24,748,209
67	(367) Underground Conductors and Devices	68,383,603	12,727,920	715,776	(68,729)	243,145	80,570,163
68	(368) Line Transformers	60,106,107	8,162,054	1,637,615	21,304	319,490	66,971,340
69	(369) Services	40,459,220	732,392	15,147	(34,167)	(26,807)	41,115,491
70	(370) Meters	11,480,123	185,739	89,530	233,293		11,809,625
71	(371) Installations on Customer Premises	3,070,739	173,539	12,091		(4,200)	3,227,987
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	2,633,285	540,305	138,179	(1,326)	(121,053)	2,913,032
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	511,089,759	32,564,216	4,952,388	43,425	796,934	539,541,946
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	6,053,756	863		(887,366)		5,167,253
87	(390) Structures and Improvements	84,132,001	2,078,710	551,971		104,042	85,762,782
88	(391) Office Furniture and Equipment	15,364,728	922,174	1,026,268		10,791	15,271,425
89	(392) Transportation Equipment	24,892,394	3,624,552	725,965	62,812		27,853,793
90	(393) Stores Equipment	166,937					166,937
91	(394) Tools, Shop and Garage Equipment	3,658,350	181,864	11,478			3,828,736
92	(395) Laboratory Equipment	792,572	11,927	33,721			770,778
93	(396) Power Operated Equipment	4,253,932	60,289	234,988			4,079,233
94	(397) Communication Equipment	6,864,775	559,559	580,829		(11,618)	6,831,887
95	(398) Miscellaneous Equipment	1,447,805	179,793	64,368			1,563,230
96	SUBTOTAL (Enter Total of lines 86 thru 95)	147,627,250	7,619,731	3,229,588	(824,554)	103,215	151,296,054
97	(399) Other Tangible Property	16,493,091	18,534				16,511,625
98	(399.1) Asset Retirement Costs for General Plant						
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	164,120,341	7,638,265	3,229,588	(824,554)	103,215	167,807,679
100	TOTAL (Accounts 101 and 106)	1,664,230,240	82,490,392	22,680,279	(781,129)	3,573,004	1,726,832,228
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)	1,664,230,240	82,490,392	22,680,279	(781,129)	3,573,004	1,726,832,228

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						
47	TOTAL					

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Ben French Station - Land	10/01/2014		45,126
3	Catron Blvd. Rapid City Campus - Land	01/31/2023		887,365
4	Kirk Station - Land	11/30/2022		2,810
5	Neil Simpson Station I - Land	10/01/2014		1,000
6	Osage Plant - Land	10/01/2014		149,038
7	St. Onge 230kV Substation - Land	07/01/2017		254,255
8				
9				
10				
11				
12				
13				
14				
21	Other Property:			
22	Osage Plant - Water/Well Assets	10/01/2014		815,962
47	TOTAL			2,155,556

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	10068176-NSC Training Simulator	1,036,692
2	10078881-Steam Plants DCS Loop Separation Phase 2	1,939,926
3	10078934-Field Area Network 2022 South Dakota Electric	1,332,948
4	10080989-69/29.4kV Mall Substation Expansion	2,363,206
5	10084596-CT1 Major Overhead and Conversion	2,003,915
6	60191198-Liberty Feeder 2A	1,095,049
7	DISTRIBUTION PLANT LESS THAN $1,000,000 EACH	7,144,788
8	GENERAL PLANT-ELECTRIC LESS THAN $1,000,000 EACH	677,735
9	OTHER GENERATION -PLANT LESS THAN $1,000,000 EACH	747,978
10	STEAM GENERATION LESS THAN $1,000,000 EACH	958,674
11	TRANSMISSION LESS THAN $1,000,000 EACH	508,409
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
43	Total	19,809,320

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

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

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 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	479,335,319	479,335,319		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	45,849,363	45,849,363		
4	(403.1) Depreciation Expense for Asset Retirement Costs	31,627	31,627		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	890,959	890,959		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Right of Use	3,361,022	3,361,022		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	50,132,971	50,132,971		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(16,865,990)	(16,865,990)		
13	Cost of Removal	(7,267,669)	(7,267,669)		
14	Salvage (Credit)	2,443,330	2,443,330		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(21,690,329)	(21,690,329)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Asset Retirement Obligation and Pending Retirements	(5,273,957)	(5,273,957)		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	[a]502,504,004	502,504,004		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	172,906,397	172,906,397		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	76,934,888	[b]76,934,888		
25	Transmission	43,694,717	43,694,717		
26	Distribution	172,715,899	172,715,899		
27	Regional Transmission and Market Operation				
28	General	36,252,103	36,252,103		
29	TOTAL (Enter Total of lines 20 thru 28)	[c]502,504,004	502,504,004		

(a) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

Note: Amounts footnoted are based upon FERC-approved rates

Section A. Balances and Changes During Year

Line No.	Item	Total (c + d+ e)	Electric Plant in Service	Electric Plant Held for Future Use	Electric Plant Leased to Others
	(a)	(b)	(c)	(d)	(e)
	Section A. Balance and Changes During Year				
1	Balance Beginning of Year	501,964,165	501,964,165		
2	**Depreciation Provisions for Year, Charged to**	47,534,272	47,534,272		
3	(403) Depreciation Expense	31,627	31,627		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt.. Leas. to Others	2,482,428	2,482,428		
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Right of Use	3,361,022	3,361,022		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	53,409,350	53,409,350		
11	**Net Charges for Plant Retired**				
12	Book Cost of Plant Retired	(16,865,990)	(16,865,990)		
13	Cost of Removal	(7,267,669)	(7,267,669)		
14	Salvage (Credit)	2,443,330	2,443,330		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(21,690,329)	(21,690,329)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Asset Retirement Obligation and Pending Retirements	(5,273,957)	(5,273,957)		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	528,409,229	528,409,229		

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

	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	172,906,397	172,906,397		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	76,934,888	76,934,888		
25	Transmission	44,835,365	44,835,365		
26	Distribution	172,715,899	172,715,899		
27	Regional Transmission and Market Operation				
28	General	61,016,679	61,016,679		
29	TOTAL (Enter Total of lines 20 thru 28)	528,409,229	528,409,229		

(b) Concept: AccumulatedDepreciationOtherProduction

Amount includes an Asset Retirement Obligation of $97,151

(c) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

Note: Amounts footnoted are based upon FERC-approved rates

Section A. Balances and Changes During Year

Line No.	Item	Total (c + d+ e)	Electric Plant in Service	Electric Plant Held for Future Use	Electric Plant Leased to Others
	(a)	(b)	(c)	(d)	(e)
	Section A. Balance and Changes During Year				
1	Balance Beginning of Year	501,964,165	501,964,165		
2	**Depreciation Provisions for Year, Charged to**	47,534,272	47,534,272		
3	(403) Depreciation Expense	31,627	31,627		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt.. Leas. to Others	2,482,428	2,482,428		
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Right of Use	3,361,022	3,361,022		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	53,409,350	53,409,350		
11	**Net Charges for Plant Retired**				
12	Book Cost of Plant Retired	(16,865,990)	(16,865,990)		
13	Cost of Removal	(7,267,669)	(7,267,669)		
14	Salvage (Credit)	2,443,330	2,443,330		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(21,690,329)	(21,690,329)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Asset Retirement Obligation and Pending Retirements	(5,273,957)	(5,273,957)		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	528,409,229	528,409,229		

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

	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	172,906,397	172,906,397		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	76,934,888	76,934,888		
25	Transmission	44,835,365	44,835,365		
26	Distribution	172,715,899	172,715,899		
27	Regional Transmission and Market Operation				
28	General	61,016,679	61,016,679		
29	TOTAL (Enter Total of lines 20 thru 28)	528,409,229	528,409,229		

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

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								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
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21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								
41								
42	Total Cost of Account 123.1 $		Total					

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	2,559,027	7,162,936	Production
2	Fuel Stock Expenses Undistributed (Account 152)			Production
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	7,829,590	7,554,563	Transmission & Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	21,986,185	23,397,837	Production
8	Transmission Plant (Estimated)	27,554	258,612	Transmission
9	Distribution Plant (Estimated)	186,902	1,296,935	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[a]1,863	[b]471,955	General
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	30,032,094	32,979,902	
13	Merchandise (Account 155)	170		
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)	2,078,990	3,561,730	
17				
20	TOTAL Materials and Supplies	34,670,281	43,704,568	

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesOther
Operations and Maintenance expenses assigned to general.
(b) Concept: PlantMaterialsAndOperatingSuppliesOther
Operations and Maintenance expenses assigned to general.

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

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		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	4,579		5,047		5,515		5,983		6,451			
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	1,411		1,411		1,411		1,411		1,411			
5	Returned by EPA												
6													
7													
8	BHP to BHC General Account												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509												
19	Other:												
20	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	5,047		5,515		5,983		6,451		6,919			
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: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

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		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year												
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA												
6													
7													
8													
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509												
19	Other:												
20	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year												
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: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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						
20	TOTAL					

FERC FORM No. 1 (ED. 12-88)

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21						
49	TOTAL					

FERC FORM No. 1 (ED. 12-88)

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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**				
20	Total				
21	**Generation Studies**				
39	Total				
40	Grand Total				

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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	[a] Energy Cost Adjustment	28,198,143	125,204,054	Various	129,881,127	23,521,070
2	Transmission Cost Adjustment	6,105,547	31,447,866	Various	31,234,903	6,318,510
3	Deferred Taxes on AFUDC	4,184,557		Various	196,681	3,987,876
4	Deferred Taxes on Flow Through Accounting	16,148,629	2,951,192			19,099,821
5	Deferred Taxes related to Retiree Healthcare Plan - Regulatory Liability	435,978		Various	21,499	414,479
6	Pension Plan	16,357,768	382,416			16,740,184
7	[b] Energy Efficiency	298,615				298,615
8	[c] South Dakota System Inspection	47,098		928	47,098	
9	[d] Regulatory Asset - Storm Atlas	143,682		588	143,682	
10	[e] Rate Case Expenses	19,552		928	19,552	
11	[f] Power Plant Decommissioning Costs	887,218		405	887,218	
12	[g] Vegetation Management	1,151,758		593	1,151,758	
44	TOTAL	73,978,545	159,985,528		163,583,518	70,380,555

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Energy Cost Adjustment and Deferred Power Cost Adjustment in the 2022 FERC Form were combined into one line for 2023 reporting as they represent the same recovery mechanism/purpose.
(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Black Hills Power has WSPC authorization to accumulate certain energy efficiency costs in a regulatory asset with determination of recovery to be made in the next rate review.
(c) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Amortization of the South Dakota System Inspection regulatory asset (approved by the South Dakota Public Commission in Docket EL14-026) was completed in 2023.
(d) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Amortization of the Storm Atlas regulatory asset (approved by the South Dakota Public Commission in Docket EL14-026) was completed in 2023.
(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Amortization of rate case expenses regulatory asset (approved by the South Dakota Public Commission in Docket EL14-026) was completed in 2023.
(f) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Amortization of the Power Plant Decommissioning Costs regulatory asset (approved by the South Dakota Public Utilities Commission in Docket EL14-026) was completed in 2023.
(g) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Amortization of the Vegetation Management regulatory asset (approved by the South Dakota Public Utilities Commission in Docket EL14-026) was completed in 2023.

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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	Tax Increment Financing (TIF) Receivable	4,528,440	234,182	548	105,831	4,656,791
2	Corriedale Spare Parts Consigned Inventory	152,671		548	23,488	129,183
3	Teckla-Osage Transmission Line Insurance Receivable	300,000		925	300,000	
4	Miscellaneous Deferred Debits	625,815	437,366	Various	18,194	1,044,987
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	5,606,926				5,830,961

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Abandonment Loss	(104,894)	(4,571)
3	Bad Debt Reserve	1,022,942	718,682
4	Bonus Compensation	189,354	289,803
5	Deferred Compensation	94,533	91,246
6	Defined Benefit Pension Plan	4,348,267	4,449,922
7	Defined Benefit Pension Plan AOCI	64,911	66,534
8	Line Extension Deposits	2,239,526	1,522,250
9	Net Operating Loss Carryforward	2,741,399	3,219,238
10	Non-qualified Pension Plan	260,469	221,227
11	Operating Leases	2,825,794	2,766,304
12	Production Tax Credits	7,988,949	11,577,888
13	Regulatory Liabilities	19,034,294	18,568,536
14	Retiree Healthcare Plan	1,038,433	1,003,838
7	Other	3,095,631	4,012,600
8	TOTAL Electric (Enter Total of lines 2 thru 7)	44,839,608	48,503,497
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	44,839,608	[a]48,503,497

Notes

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Note: Amounts footnoted are based upon FERC-approved rates

	Description and Location	Balance at Beginning of Year	Balance at End of Year
Line No.	(a)	(b)	(c)
1	Electric		
2	Abandonment Loss	(104,894)	(4,571)
3	Bad Debt Reserve	1,022,942	718,682
4	Bonus Compensation	189,354	289,803
5	Deferred Compensation	94,533	91,246
6	Defined Benefit Pension Plan	4,348,267	4,449,922
7	Defined Benefit Pension Plan AOCI	64,911	66,534
8	Line Extension Deposits	2,239,526	1,522,250
9	Net Operating Loss Carryforward	2,741,398	3,219,238
10	Non-qualified Pension Plan	260,469	221,227
11	Operating Leases	2,825,794	2,766,304
12	Production Tax Credits	7,988,949	11,577,888
13	Regulatory Liabilities	19,034,294	18,073,934
14	Retiree Healthcare Plan	1,038,433	1,003,838
15	Other	3,095,632	4,012,600
16	TOTAL Electric (Enter Total of lines 2 thru 7)	44,839,608	48,008,895
17			
18			
19	Gas		
20			
21			
22			
23	Other		
24	TOTAL Gas (Enter of lines 10 thru 15)		
25	Other (Specify)		
26	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	44,839,608	48,008,895

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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	Common Stock	50,000,000	1		23,416,396	23,416,396				
8	Total					23,416,396				
9	Preferred Stock (Account 204)									
11	Total									
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
3	Total									

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2023-12-31	Year/Period of Report End of: 2023/ 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		
4	Ending Balance Amount	
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1		
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11.1		
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	
15.1		
16	Ending Balance Amount	
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19.1		
20	Ending Balance Amount	
40	Total	

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock $1.00 Par Value	2,501,882
22	TOTAL	2,501,882

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2	2002 AT Bonds, 7.23%	Various	75,000,000		991,063	0	0	08/13/2002	08/15/2032	08/13/2002	08/15/2032	75,000,000	5,422,500
3	2009 AF Bonds, 6.125%	Various	180,000,000		2,277,473	0	124,200	10/27/2009	11/01/2039	10/27/2009	10/31/2039	180,000,000	11,025,000
4	2014 AG Bonds, 4.43%	Various	85,000,000		716,799	0	0	10/01/2014	10/20/2044	10/01/2014	09/30/2044	85,000,000	3,765,500
5	Subtotal		340,000,000		3,985,335	0	124,200					340,000,000	20,213,000
6	Reacquired Bonds (Account 222)												
7													
10	Subtotal												
11	Advances from Associated Companies (Account 223)												
12													
15	Subtotal												
16	Other Long Term Debt (Account 224)												
17													
20	Subtotal												
33	TOTAL		340,000,000									340,000,000	20,213,000

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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)	54,758,609
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		
9	Deductions Recorded on Books Not Deducted for Return	
10	Nondeductible and deferred taxes - principally federal income	5,013,912
11	Benefits Addback	1,013,813
12	Other Comprehensive Income	64,332
13	Operating Lease Asset	284,202
14	Straight Line Lease Asset	6,623
15	Reaquired Bond Loss	184,959
16	Fines & Penalties	107,678
17	FAS 143 Asset Retirement Obligation	56,596
18	Club Dues	22,894
19	Lobbying	12,892
20	Entertainment	6,126
21	Captive Insurance	428,689
22	Meals	128,263
23	Line Extension Deposit	158,273
24	Deferred Regulatory Asset	6,778,710
14	Income Recorded on Books Not Included in Return	
15	Operating Lease Liability	(283,288)
16	Public Utilities Commission Fees	(14,469)
17	Insurance Reserve	(80,000)
18	Prepaid Expense	(246,843)
19	Bad Debt Reserve	(1,448,856)
20	Benefits	(4,239,060)
21	Depreciation	(40,403,914)
22	Officer Supplemental Life Insurance	(164,769)
23	NOL Carryforward	(22,123,609)
24	Other	(21,766)
19	Deductions on Return Not Charged Against Book Income	
20		
27	Federal Tax Net Income	(40,644,636)
28	Show Computation of Tax:	
29	Tax Amount	
30	Subtotal	
31	Tax Return True-up Adjustment	
32	Intercompany Payment	4,296,700
33	Total	4,296,700

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR: Taxes Accrued (Account 236) (e)	BALANCE AT BEGINNING OF YEAR: Prepaid Taxes (Include in Account 165) (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR: Taxes Accrued (Account 236) (j)	BALANCE AT END OF YEAR: Prepaid Taxes (Included in Account 165) (k)	DISTRIBUTION OF TAXES CHARGED: Electric (Account 408.1, 409.1) (l)	DISTRIBUTION OF TAXES CHARGED: Extraordinary Items (Account 409.3) (m)	DISTRIBUTION OF TAXES CHARGED: Adjustment to Ret. Earnings (Account 439) (n)	DISTRIBUTION OF TAXES CHARGED: Other (o)
1	Federal Unemployment Tax	Unemployment Tax	Federal	2023	7,195		17,191	24,386				6,166			11,025
2	Federal Insurance Contribution Tax	Federal Insurance Tax	Federal	2023	167,457		3,353,235	3,385,502		135,190		1,947,929			[a]1,405,307
3	Federal Income Tax	Income Tax	Federal	2023	1		(4,038,854)	5,457,708	9,496,561			4,050,288			(11,435)
4	State Unemployment Tax	Unemployment Tax	SD	2023	1,283		8,611	9,894				39,455			(30,844)
5	State Income Tax	State Tax	MT	2023			257,846	257,846				257,846			
6	Property Tax	Property Tax	SD	2023	6,051,792		4,979,553	5,198,767		5,832,578		4,979,553			
7	Property Tax	Property Tax	WY	2023	1,288,141		2,962,573	3,088,725		1,161,989		2,962,573			
8	Property Tax	Property Tax	MT	2023	240,262		558,379	591,649		206,992		558,379			
9	Property Tax	Property Tax	NE	2023	139,813		171,177	166,205		144,785		171,177			
10	Accrued City Franchise Fee	Franchise Tax	WY	2023			76,929	76,929				74,529			2,400
11	Accrued Sales/Use Tax	Sales And Use Tax	SD	2023	95,737		87,071	156,867		25,941		(2,227)			89,298
12	Accrued Sales/Use Tax	Sales And Use Tax	WY	2023	33,443		70,432	101,364		2,511		(5,240)			75,672
13	Regulatory Tax	Other State Tax	MT	2023			69,407	69,407				56,426			
40	TOTAL				8,025,124	0	8,573,550	18,585,249	9,496,561	7,509,986	0	15,096,854	0	0	1,541,423

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: TaxesIncurredOther

Allocation of payroll taxes to operating and maintenance expenses and capital assets.

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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									
8	TOTAL Electric (Enter Total of lines 2 thru 7)									
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
47	OTHER TOTAL									
48	GRAND TOTAL									

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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	Contractor Retainage	1,400,211	various	5,720,977	5,720,050	1,399,284
2	Deferred Revenue	515	various	628,108	627,593	
3	Estimated Contract Liability	1,469,450	various	478,093	535,247	1,526,604
4	Other	62	242	125	63	
47	TOTAL	2,870,238		6,827,303	6,882,953	2,925,888

FERC FORM NO. 1 (ED. 12-94)

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

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

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities										
5	Other										
5.1	Other										
5.2	Other										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other										
12.2	Other										
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: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	150,803,951	9,065,044	1,607,659			182.3	(2,331,442)	182.3	(155,379)	160,437,399
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	150,803,951	9,065,044	1,607,659				(2,331,442)		(155,379)	160,437,399
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	150,803,951	9,065,044	1,607,659				(2,331,442)		(155,379)	[a]160,437,399
10	Classification of TOTAL										
11	Federal Income Tax	150,803,951	9,065,044	1,607,659			182.3	(2,331,442)	182.3	(155,379)	160,437,399
12	State Income Tax										
13	Local Income Tax										

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Note: Amounts footnoted are based upon FERC-approved rates

			Changes During Year				Adjustments				
							Debits		Credits		
	Account	Balance at Beg of Year	Amounts Debited to Account 410.1	Amounts Credited to Account 411.1	Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account Credited	Amount	Account Debited	Amount	Balance at End of Year
Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Account 282**										
2	Electric	150,803,951	3,929,973	1,607,659			182.3	(2,331,442)	182.3	(155,378)	155,302,329
3	Gas										
4	Other (Define)										
5	Total	150,803,951	3,929,973	1,607,659				(2,331,442)		(155,378)	155,302,329
6											
7	TOTAL Account 282	150,803,951	3,929,973	1,607,659				(2,331,442)		(155,378)	155,302,329
8	**Classification of TOTAL**										
9	Federal Income Tax	150,803,951	3,929,973	1,607,659			182.3	(2,331,442)	182.3	(155,378)	155,302,329
10	State Income Tax										
11	Local Income Tax										

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	AFUDC	504					182.3		182.3	(163)	341
4	Deferred Costs	7,391,176	27,823	929,754							6,489,245
5	Flow Through	4,269,465					182.3	(619,750)	182.3	(41,140)	4,848,075
6	Goodwill	180,962		20,455							160,507
7	Operating Lease Asset	2,823,281		61,073							2,762,208
8	Partnerships	33,705	9,560								43,265
9	Pension	2,602,965		81,464							2,521,501
10	Prepaid Expenses	502,657	428,267	399,187							531,737
11	Reacquired Bond Loss	65,886		38,842							27,044
9	TOTAL Electric (Total of lines 3 thru 8)	17,870,601	465,650	1,530,775				(619,750)		(41,303)	17,383,923
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other										
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	17,870,601	465,650	1,530,775				(619,750)		(41,303)	[a]17,383,923
20	Classification of TOTAL										
21	Federal Income Tax	17,870,601	465,650	1,544,285				(633,260)		(41,303)	17,383,923
22	State Income Tax										
23	Local Income Tax										

NOTES

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

Note: Amounts footnoted are based upon FERC-approved rates

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
	Account	Balance at Beginning of Year	Amounts Debited to Account 410.1	Amounts Credited to Account 411.1	Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account Credited	Amount	Account Debited	Amount	Balance at End of Year
Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Account 283**										
2	Electric										
3	AFUDC	504							182.3	(163)	341
4	Deferred Costs	7,391,176	27,823	929,754							6,489,245
5	Derivative	0		13,510			219	(13,510)			-
6	Flow Through	4,269,465					182.3	(659,693)	182.3	(41,140)	4,888,018
7	Goodwill	180,962		20,455							160,507
8	Operating Lease Asset	2,823,281		61,073							2,762,208
9	Partnerships	33,705	9,560								43,265
10	Pension	2,602,965		81,464							2,521,501
11	Prepaid Expenses	502,657	428,267	399,187							531,736
12	Reacquired Bond Loss	65,886		38,842							27,045
13											
14	**TOTAL Electric (Total of lines 3 thru 12)**	17,870,601	465,650	1,544,285				(673,203)		(41,303)	17,423,866
15	Gas										
16											
17											
18											
19											
20	TOTAL Gas (Total of lines 15 thru 19)										
21	TOTAL Other										
22	TOTAL (Acct 283) (Enter Total of lines 12, 20, and 21)	17,870,601	465,650	1,544,285				(673,203)		(41,303)	17,423,866
23	**Classification of TOTAL**										
24	Federal Income Tax	17,870,601	465,650	1,544,285				(673,203)		(41,303)	17,423,866
25	State Income Tax										
26	Local Income Tax										

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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	Deferred Maintenance	501,653	512		434,448	936,101
2	[a] Excess Deferred Income Taxes	90,544,371	Various	2,397,517	268,802	88,415,656
3	Deferred Taxes related to Pension Plan Regulatory Asset	4,348,268	Various		101,655	4,449,923
4	Retiree Healthcare Plan	1,640,107	228	80,877		1,559,230
41	TOTAL	97,034,399		2,478,394	804,905	95,360,910

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Note: Amounts footnoted are based upon FERC-approved rates

			Debits			
	Description and Purpose of Other Liabilities	Balance at Beginning of Current Quarter/Year	Account Credited	Amount	Credits	Balance at End of Current Quarter/Year
Line No.	(a)	(b)	(c)	(d)	(e)	(f)
2	Excess Deferred Income Taxes	90,544,372		4,752,766	268,802	86,060,408

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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	77,112,025	82,447,008	565,837	594,312	61,785	60,929
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	97,037,562	101,716,321	772,949	778,554	13,861	13,812
5	Large (or Ind.) (See Instr. 4)	36,927,877	38,377,056	469,450	468,928	24	24
6	(444) Public Street and Highway Lighting	1,207,305	1,222,227	10,015	10,151	217	222
7	(445) Other Sales to Public Authorities	2,156,471	2,346,912	21,701	23,268	149	148
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	214,441,240	226,109,524	1,839,952	1,875,213	76,036	75,135
11	(447) Sales for Resale	51,855,375	60,163,609	715,649	778,097	445	35
12	TOTAL Sales of Electricity	266,296,615	286,273,133	2,555,601	2,653,310	76,481	75,170
13	(Less) (449.1) Provision for Rate Refunds	416,728	46,144				
14	TOTAL Revenues Before Prov. for Refunds	265,879,887	286,226,989	2,555,601	2,653,310	76,481	75,170
15	Other Operating Revenues						
16	(450) Forfeited Discounts	281,631	264,394				
17	(451) Miscellaneous Service Revenues	[a]415,098	413,713				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	21,371,088	19,689,180				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[b]1,004,842	1,487,628				
22	(456.1) Revenues from Transmission of Electricity of Others	39,668,357	35,827,218				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	62,741,016	57,682,133				
27	TOTAL Electric Operating Revenues	328,620,903	343,909,122				

Line12, column (b) includes $ of unbilled revenues.
Line12, column (d) includes MWH relating to unbilled revenues

FOOTNOTE DATA

(a) Concept: MiscellaneousServiceRevenues
Consists of site visit and interconnection revenue.
(b) Concept: OtherElectricRevenue
Includes Planning Reserves and Wheeling Charges

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

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					
46	TOTAL				

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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	SD710 - Regular Service	377,388	48,755,472	47,485	7,948	0.129
2	MT912 - Total Electric	12	639	1	12,000	0.053
3	SD714 - Demand Service	15,865	1,621,262	843	18,820	0.102
4	SD716 - Demand Service Max	65,939	6,104,403	3,059	21,556	0.093
5	WY914 - Demand Service	197	23,872	11	17,909	0.121
6	WY916 - Demand Service Max	1,553	181,600	83	18,711	0.117
7	SD717 - Utility Controlled	61	4,041	2	30,500	0.066
8	SD798 - Rental					
9	SD799 - Rental		2,054	30		
10	WY798 - Rental		130	2		
11	SDA24 - Private Area Lighting-A	761	117,492	936	813	0.154
12	SD875 - Regular Service	651	91,791	83	7,843	0.141
13	SDB24 - Private Area Lighting-B	60	13,307	16	3,750	0.222
14	SDC24 - Private Area Lighting-C	1	93	2	500	0.093
15	WYA24 - Private Area Lighting-A	39	7,363	52	750	0.189
16	WYB24 - Private Area Lighting-B					
17	Energy Cost Adjustment		9,054,346			
18	WY910 - Regular Service	13,923	1,712,927	1,525	9,130	0.123
19	MT910 - Regular Service	149	10,094	12	12,417	0.068
20	SD712 - Total Electric	93,633	9,707,813	7,264	12,890	0.104
21	SD876 - Net Billing Total Electric	227	25,581	19	11,947	0.113
22	SD887 - Net Billing Total Electric Max	359	37,239	17	21,118	0.104
23	WY912 -Total Electric	4,151	486,126	342	12,137	0.117
24	WY913 - Total Electric	8	999	1	8,000	0.125
41	TOTAL Billed Residential Sales	574,977	77,958,644	61,785	9,306	0.136
42	TOTAL Unbilled Rev. (See Instr. 6)	(9,140)	(846,619)			0.093
43	TOTAL	565,837	77,112,025	61,785	9,158	0.136

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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	SD718 - General Service-No Demand	694	75,950	48	14,458	0.109
2	MT920 - General Service	185	21,725	22	8,409	0.117
3	SD723 - General Service-Total Electric	34,114	3,814,983	790	43,182	0.112
4	WY923 - General Service-Total Electric	1,176	131,427	39	30,154	0.112
5	MT923 - General Service-Total Electric	10	812	2	5,000	0.081
6	SD721 - Large General Service-Secondary	80,618	8,040,985	88	916,114	0.100
7	SD771 - Large General Service	34,626	2,486,258	1	34,626,000	0.072
8	SD731 - Large General Service	41,599	3,322,416	6	6,933,167	0.080
9	SD827 - Large General Service	171,387	14,100,733	110	1,558,064	0.082
10	WY921 - Large General Service-Secondary	2,146	225,949	3	715,333	0.105
11	SD722 - Large Demand Curtailable Service	611	45,960	1	611,000	0.075
12	SD720 - General Service	358,204	45,812,096	10,719	33,418	0.128
13	SD755 - Energy Storage Service	9,687	714,246	28	345,964	0.074
14	SD726 - Irrigation Pumping	620	97,853	25	24,800	0.158
15	SD727 - Utility Controlled General Service	1,344	92,273	12	112,000	0.069
16	SD750 - Small Interruptible General Service	58	5,567	1	58,000	0.096
17	SD798 - Rental		2,594	4		
18	SD799 - Rental		24,278	167		
19	WY798 - Rental		1,007	13		
20	SDA24 - Private Area Lighting-A	1,712	236,498	899	1,904	0.138
21	SDB24 - Private Area Lighting-B	608	119,320	165	3,685	0.196
22	SDC24 - Private Area Lighting-C	123	8,921	15	8,200	0.073
23	SD770 - General Service-Special Events	1,425	231,715	122	11,680	0.163
24	WYA24 - Private Area Lighting-A	64	12,308	43	1,488	0.192
25	WYB24 - Private Area Lighting-B	39	8,714	12	3,250	0.223
26	Energy Cost Adjustment		11,981,817			
27	[a] Renewable Ready		1,565,267			
28	SD826 - Large General Service	11,598	1,152,961	31	374,129	0.099
29	SD878 - Net Billing General Service	802	112,939	19	42,211	0.141
30	SD879 - General Service	32	4,958	1	32,000	0.155
31	SD890 - Large General Service	498	60,578	1	498,000	0.122
32	WY918 - General Service-No Demand	27	3,470	3	9,000	0.129
33	WY920 - General Service	22,684	2,913,231	471	48,161	0.128
41	TOTAL Billed Small or Commercial	776,691	97,429,809	13,861	56,034	0.125
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(3,742)	(392,247)			0.105
43	TOTAL Small or Commercial	772,949	97,037,562	13,861	55,764	0.126

FOOTNOTE DATA

(a) Concept: DescriptionOfNumberAndTitleOfRateSchedule

The Renewable Ready Service Tariff is a voluntary green pricing program that allows large commercial and industrial customers (annual usage of at least 300,000 kW) the option to fulfill up to 100% of their electricity needs using renewable energy direct from Black Hills Power. The term of the Renewable Ready Subscriber Agreement is a minimum of five years and a maximum of 25 years plus any one-year renewal terms.

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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.
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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	SD720 - General Service	219	162,881	2	109,500	0.744
2	SD764 - Industrial Contract Services-Forest Products-Primary	24,921	1,826,931	1	24,921,000	0.073
3	SD774 - Industrial Contract Services-Forest Products-Primary	50,215	3,219,601	1	50,215,000	0.064
4	SD798 - Rental					
5	SD799 - Rental					
6	WY798 - Rental		305	1		
7	SDA24 - Private Area Lighting-A	2	316	1	2,000	0.158
8	SDB24 - Private Area Lighting-B	2	490	1	2,000	0.245
9	SDC24 - Private Area Lighting-C					
10	WYA24 - Private Area Lighting-A					
11	WYB24 - Private Area Lighting-B	11	2,566	1	11,000	0.233
12	WY921 - General Service Large	7,309	905,772	1	7,309,000	0.124
13	Energy Cost Adjustment		4,395,392			
14	Renewable Ready		1,470,068			
15	WY934 - General Service Large	47,791	4,101,746	6	7,965,167	0.086
16	MT920 - General Service Large	24	2,066	3	8,000	0.086
17	MT930 - General Service Large	3,681	300,886	1	3,681,000	0.082
18	MT931 - General Service Large	9,941	937,878	2	4,970,500	0.094
19	MT932 - General Service Large	135,661	8,396,785	1	135,661,000	0.062
20	SD761 - Industrial Contract Transmission	124,781	6,779,916	1	124,781,000	0.054
21	WY931 - Industrial Contract Services	61,611	4,220,350	1	61,611,000	0.068
41	TOTAL Billed Large (or Ind.) Sales	466,169	36,723,949	24	19,423,708	0.079
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	3,281	203,928			0.062
43	TOTAL Large (or Ind.)	469,450	36,927,877	24	19,560,417	0.079

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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	SD741 - Customer Owned Service	6,165	439,625	34	181,324	0.071
2	SD742 - Traffic Signals	671	75,273	120	5,592	0.112
3	SD798 - Rental		240	1		
4	SD799 - Rental		16,274	7		
5	SD840 - Company Owned Service	2,740	590,680	35	78,286	0.216
6	SD841 - Customer Owned Service	129	13,169	8	16,125	0.102
7	SDA24 - Private Area Lighting	5	746	4	1,250	0.149
8	SDB24 - Private Area Lighting	1	269	1	1,000	0.269
9	SDC24 - Private Area Lighting	8	671	2	4,000	0.084
10	WY940 - Company Owned Service	238	64,360	1	238,000	0.270
11	WY941 - Customer Owned Service	49	4,209	1	49,000	0.086
12	WY942 - Traffic Signals	9	1,789	3	3,000	0.199
41	TOTAL Billed Public Street and Highway Lighting	10,015	1,207,305	217	46,152	0.121
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	10,015	1,207,305	217	46,152	0.121

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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	Energy Cost Adjustment		212,863			
2	Renewable Ready		18,212			
3	SD720 - Municipal Pumping	876	125,982	45	19,467	0.144
4	SD723 - Municipal Pumping	16	1,896	2	8,000	0.119
5	SD726 - Municipal Pumping	16	3,293	1	16,000	0.206
6	SD743 - Municipal Pumping	20,593	1,768,013	92	223,837	0.086
7	WY943 - Municipal Pumping	456	52,878	9	50,667	0.116
41	TOTAL Billed Other Sales to Public Authorities	21,957	2,183,137	149	147,362	0.099
42	TOTAL Unbilled Rev. (See Instr. 6)	(256)	(26,666)			0.104
43	TOTAL	21,701	2,156,471	149	145,644	0.099

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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						
2						
3						
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41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		416,728			

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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)
41	TOTAL Billed - All Accounts	1,849,809	215,502,844	76,036	24,328	0.117
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(9,857)	(1,061,604)			0.108
43	TOTAL - All Accounts	1,839,952	214,441,240	76,036	24,198	0.117

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

   LF - for 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)		Megawatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	
1	City of Gillette Wy	RQ	34	23	23	23	35,321		1,191,270		1,191,270
2	Montana Dakota Utilities	RQ	3	47	47	47	111,664	2,510,311	4,017,586	[b]1,793,077	8,320,974
3	Municipal Energy Agency of Nebraska (MEAN)	LU	3				107,233		6,230,109		6,230,109
4	PacifiCorp	OS	3				21,439		2,319,545		2,319,545
5	Western Area Power Administration - Loveland Area Power	OS	3				56,649		2,766,481		2,766,481
6	Western Area Power Administration - Colorado River Storage Project	OS	3				430		950		950
7	Western Area Power Administration-WACM Marketing	OS	3				(601)		418,879		418,879
8	WACM-North West Power Pool	OS	3				1,263		64,827		64,827
9	Basin Electric Power	OS	3				94		2,350		2,350
10	Bonneville Power	OS	3				32,800		2,596,106		2,596,106
11	Brookfield	OS	3				3,800		126,000		126,000
12	[a] Cheyenne Light Fuel and Power	OS	3				56,633		2,565,528		2,565,528
13	Citigroup Energy	OS	3				47,625		3,080,062		3,080,062
14	City of St George	OS	3				340		24,300		24,300
15	Colorado Springs Utilities	OS	3				2,820		175,325		175,325
16	Constellation Power/Exelon	OS	3				8,800		488,457		488,457
17	Coral Power	OS	3				110,788		8,364,828		8,364,828
18	Dynasty Power	OS	3				2,920		141,592		141,592
19	Energy Keepers	OS	3				600		24,952		24,952
20	El Paso Electric	OS	3				800		118,000		118,000
21	Guzman Energy	OS	3				6,144		278,342		278,342
22	Macquarie Energy	OS	3				21,820		1,618,526		1,618,526
23	Mercuria	OS	3				2,453		249,685		249,685
24	Morgan Stanley	OS	3				3,614		312,650		312,650
25	Portland General Electric	OS	3				800		80,000		80,000
26	Public Service Company of Colorado	OS	3				1,680		98,710		98,710
27	Public Service Company of New Mexico	OS	3				8,910		964,462		964,462
28	Southwest Power Pool-WEIS	OS	SPP RTO							[c]2,278,361	2,278,361
29	Tenaska Power	OS	3				4,800		395,900		395,900
30	The Energy Authority (MEAN)	OS	3				2,975		194,985		194,985
31	TransAlta Energy	OS	3				19,200		2,012,248		2,012,248
32	Tri-State Generation	OS	3				8,315		335,350		335,350
33	Uniper Global	OS	3				12,600		952,081		952,081
34	UNS Electric	OS	3				1,270		45,440		45,440
35	Utah Associated Municipal Power	OS	3				16,450		2,580,900		2,580,900
36	Utah Municipal Power Agency	OS	3				3,200		437,200		437,200
15	Subtotal - RQ						146,985	2,510,311	5,208,856	1,793,077	9,512,244

16	Subtotal-Non-RQ							568,664		40,064,770	2,278,361	42,343,131
17	Total							715,649	2,510,311	45,273,626	4,071,438	51,855,375

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Affiliate Transaction
(b) Concept: OtherChargesRevenueSalesForResale
Other Charges - Expense Reimbursements
(c) Concept: OtherChargesRevenueSalesForResale
Other Charges - Energy Imbalance Market

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,547,403	1,288,123
5	(501) Fuel	23,244,582	21,678,087
6	(502) Steam Expenses	1,508,409	1,015,606
7	(503) Steam from Other Sources	0	0
8	(Less) (504) Steam Transferred-Cr.	0	
9	(505) Electric Expenses	608,529	580,374
10	(506) Miscellaneous Steam Power Expenses	1,495,317	1,573,400
11	(507) Rents	3,345,937	3,081,029
12	(509) Allowances	0	
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	31,750,177	29,216,619
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	861,149	881,193
16	(511) Maintenance of Structures	679,641	604,158
17	(512) Maintenance of Boiler Plant	5,201,051	3,253,711
18	(513) Maintenance of Electric Plant	1,279,924	952,772
19	(514) Maintenance of Miscellaneous Steam Plant	33,201	1,363,427
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	8,054,966	7,055,261
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	39,805,143	36,271,880
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		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		

59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,061,948	928,727
63	(547) Fuel	14,920,362	16,232,105
64	(548) Generation Expenses	1,281,527	846,636
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	351,551	522,620
66	(550) Rents	2,358,216	1,731,829
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	19,973,604	20,261,917
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	11,543	4,992
70	(552) Maintenance of Structures	4,322	6,114
71	(553) Maintenance of Generating and Electric Plant	1,757,748	2,112,625
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	9,587	23,643
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	1,783,200	2,147,374
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	21,756,804	22,409,291
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	27,501,412	47,759,976
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	1,343,261	1,195,849
78	(557) Other Expenses	3,718	
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	28,848,391	48,955,825
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	90,410,338	107,636,996
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	839,257	839,693
85	(561.1) Load Dispatch-Reliability		154,057
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	855,648	736,910
87	(561.3) Load Dispatch-Transmission Service and Scheduling	180,935	256,629
88	(561.4) Scheduling, System Control and Dispatch Services	286,633	280,097
89	(561.5) Reliability, Planning and Standards Development	965,209	639,603
90	(561.6) Transmission Service Studies		258
91	(561.7) Generation Interconnection Studies	496	(18,544)
92	(561.8) Reliability, Planning and Standards Development Services	267,640	135,015
93	(562) Station Expenses	395,974	404,720
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	66,330	108,205
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	27,115,755	26,492,301
97	(566) Miscellaneous Transmission Expenses	631,358	494,181
98	(567) Rents	(23,908)	24,438
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	31,581,327	30,547,563
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures	18,259	36,809
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	86,852	96,970
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	102,452	682,482
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		1,225
111	TOTAL Maintenance (Total of Lines 101 thru 110)	207,563	817,486
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	31,788,890	31,365,049
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation	199,055	
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		

120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	199,055	
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)	199,055	
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,287,033	1,173,414
135	(581) Load Dispatching	613,394	589,417
136	(582) Station Expenses	669,177	667,491
137	(583) Overhead Line Expenses	262,270	289,356
138	(584) Underground Line Expenses	434,225	415,802
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	61,727	85,518
140	(586) Meter Expenses	510,591	519,678
141	(587) Customer Installations Expenses	373,200	424,599
142	(588) Miscellaneous Expenses	1,517,788	1,646,916
143	(589) Rents	7,126	12,507
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	5,736,531	5,824,698
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	18,315	13,723
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	168,580	273,538
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	7,116,837	8,932,743
150	(594) Maintenance of Underground Lines	354,051	310,964
151	(595) Maintenance of Line Transformers	69,504	80,447
152	(596) Maintenance of Street Lighting and Signal Systems	40,918	41,316
153	(597) Maintenance of Meters	150,922	181,228
154	(598) Maintenance of Miscellaneous Distribution Plant	41,445	48,804
155	TOTAL Maintenance (Total of Lines 146 thru 154)	7,960,572	9,882,763
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	13,697,103	15,707,461
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	68,534	63,511
160	(902) Meter Reading Expenses	130,079	97,335
161	(903) Customer Records and Collection Expenses	1,284,441	1,256,340
162	(904) Uncollectible Accounts	388,632	416,933
163	(905) Miscellaneous Customer Accounts Expenses	230,094	241,519
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	2,101,780	2,075,638
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	48,435	32,763
168	(908) Customer Assistance Expenses	590,139	623,905
169	(909) Informational and Instructional Expenses	8,080	44,046
170	(910) Miscellaneous Customer Service and Informational Expenses	975	5,045
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	647,629	705,759
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	1,671	3,569
176	(913) Advertising Expenses	5,913	10,274
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	7,584	13,843
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	15,162,616	14,158,909
182	(921) Office Supplies and Expenses	4,446,784	5,195,198

183	(Less) (922) Administrative Expenses Transferred-Credit	3,680,561	3,605,159
184	(923) Outside Services Employed	4,070,688	5,010,626
185	(924) Property Insurance	1,240,734	912,579
186	(925) Injuries and Damages	2,214,405	1,670,419
187	(926) Employee Pensions and Benefits	6,942,488	6,505,663
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	901,817	1,335,989
190	(929) (Less) Duplicate Charges-Cr.	363,255	262,361
191	(930.1) General Advertising Expenses	311,978	716,553
192	(930.2) Miscellaneous General Expenses	750,006	1,934,027
193	(931) Rents	1,887,360	1,870,577
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	33,885,060	35,443,020
195	Maintenance		
196	(935) Maintenance of General Plant	3,122,148	2,560,678
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	37,007,208	38,003,698
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	175,859,587	195,508,444

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

PURCHASED POWER (Account 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

   EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES: MegaWatt Hours Received (i)	POWER EXCHANGES: MegaWatt Hours Delivered (j)	COST/SETTLEMENT OF POWER: Demand Charges ($) (k)	COST/SETTLEMENT OF POWER: Energy Charges ($) (l)	COST/SETTLEMENT OF POWER: Other Charges ($) (m)	COST/SETTLEMENT OF POWER: Total (k+l+m) of Settlement ($) (n)
1	PacifiCorp Colstrip	(f) LF	236	50	50	46	322,050					8,975,825	(au) 904,881	9,880,706
2	PacifiCorp	(g) OS	181				13,262					611,799		611,799
3	Basin Electric Power	(h) OS					33,973					1,734,197		1,734,197
4	BP Energy Company	(i) OS					160					5,600		5,600
5	Brookfield	(j) OS					1,648					96,585		96,585
6	(a) Cheyenne Light Fuel and Power	(k) OS					13,332					960,856		960,856
7	(b) Cheyenne Light Fuel and Power - Happy Jack Wind	(l) OS					29,398					1,528,494		1,528,494
8	(c) Cheyenne Light Fuel and Power Silver Sage Wind	(m) OS					52,208					3,487,847		3,487,847
9	Citigroup	(n) OS					631					52,511		52,511
10	Colorado Springs Utilities	(o) OS					1,717					96,029		96,029
11	(d) Corriedale Wind	(p) OS					126,371					3,599,149		3,599,149
12	Coral Power	(q) OS										(10,800)		(10,800)
13	Dynasty Power	(r) OS					174					32,880		32,880
14	Eagle Energy	(s) OS					10					600		600
15	Eagle Energy	(t) OS										(1,371)		(1,371)
16	(e) Fall River Solar	(u) OS					86,284					2,378,226		2,378,226
17	Guzman Energy	(v) OS					3,697					289,271		289,271
18	Idaho Power	(w) OS					545					4,100		4,100
19	Macquarie Energy	(x) OS					5,473					484,417		484,417
20	Mercuria	(y) OS					125					17,575		17,575
21	Morgan Stanley	(z) OS					1,175					77,654		77,654
22	Northwestern Energy	(aa) OS					823					10,004		10,004
23	Platte River Power Authority	(ab) OS					3,387					162,459		162,459
24	Platte River Power Authority-Silver Sage Wind	(ac) OS					31,271					626,800		626,800
25	Public Service Company of Colorado	(ad) OS					10,930					311,734		311,734
26	Public Service Company of New Mexico	(ae) OS					1,094					3,193		3,193

27	Southwest Power Pool	[af] OS					43,185					986,900		986,900
28	Southwest Power Pool-WEIS	[ag] OS	SPP RTO										[av] 1,024,263	1,024,263
29	Spearfish, (City of) - Spearfish Hydro	[ah] OS					21,448					703,831		703,831
30	The Energy Authority (MEAN)	[ai] OS					3,284					66,319		66,319
31	Tri State Generation	[aj] OS					1,747					50,488		50,488
32	Tucson Electric	[ak] OS					20					900		900
33	Uniper Global Commodities	[al] OS					3,894					170,349		170,349
34	Western Area Power Administration - Colorado River Storage Project	[am] OS					3,248					(488,111)		(488,111)
35	Western Area Power Administration - Loveland Area Power	[an] OS					8,099					(224,562)		(224,562)
36	Western Area Power Administration - Upper Great Plains	[ao] OS					468					(25,080)		(25,080)
37	WACM-North West Power Pool	[ap] OS					724					(9,805)		(9,805)
38	Western Area Power Administration	EX							[ar] 153,079	[as] 332,218			[aw] (1,310,290)	(1,310,290)
39	Deriva Energy	EX											[ax] 96,541	96,541
40	Renewable Energy Rate 44	[aq] OS										[at] 19,154		19,154
15	TOTAL						825,855	0	153,079	332,218		26,786,017	715,395	27,501,412

FERC FORM NO. 1 (ED. 12-90)

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Affiliate Transaction

(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Affiliate Transaction

(c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Affiliate Transaction

(d) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Represents the energy used from the Corriedale wind farm, which is jointly-owned by Cheyenne Light, Fuel and Power and affiliate Black Hills Power, for customers that are subscribing to the Renewable Ready Service Tariff.

(e) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Represents Black Hills Power's power purchase agreement with Fall River Solar, LLC which allows Black Hills Power to purchase up to 80 MW of renewable solar energy upon completion of a new solar facility, owned by Fall River Solar, LLC, which achieved commercial operation in the third quarter of 2023.

(f) Concept: StatisticalClassificationCode

Termination date 12/31/2023.

(g) Concept: StatisticalClassificationCode

Market based sales.

(h) Concept: StatisticalClassificationCode

Market based sales.

(i) Concept: StatisticalClassificationCode

Market based sales.

(j) Concept: StatisticalClassificationCode

Market based sales.

(k) Concept: StatisticalClassificationCode

Market based sales.

(l) Concept: StatisticalClassificationCode

Market based sales.

(m) Concept: StatisticalClassificationCode

Market based sales.

(n) Concept: StatisticalClassificationCode

Market based sales.

(o) Concept: StatisticalClassificationCode

Market based sales.

(p) Concept: StatisticalClassificationCode

Market based sales.

(q) Concept: StatisticalClassificationCode

Market based sales.

(r) Concept: StatisticalClassificationCode

Market based sales.

(s) Concept: StatisticalClassificationCode

Market based sales.

(t) Concept: StatisticalClassificationCode

Market based sales.

(u) Concept: StatisticalClassificationCode

Market based sales.

(v) Concept: StatisticalClassificationCode

Market based sales.

(w) Concept: StatisticalClassificationCode

Market based sales.

(x) Concept: StatisticalClassificationCode

Market based sales.

(y) Concept: StatisticalClassificationCode

Market based sales.

(z) Concept: StatisticalClassificationCode

Market based sales.

(aa) Concept: StatisticalClassificationCode

Market based sales.

(ab) Concept: StatisticalClassificationCode

Market based sales.

(ac) Concept: StatisticalClassificationCode

Market based sales.

(ad) Concept: StatisticalClassificationCode

Market based sales.

(ae) Concept: StatisticalClassificationCode

Market based sales.

(af) Concept: StatisticalClassificationCode

Market based sales.

(ag) Concept: StatisticalClassificationCode

Energy Imbalance Market.

(ah) Concept: StatisticalClassificationCode

Market based sales.

(ai) Concept: StatisticalClassificationCode

Market based sales.

(aj) Concept: StatisticalClassificationCode

Market based sales.

(ak) Concept: StatisticalClassificationCode

Market based sales.

(al) Concept: StatisticalClassificationCode

Market based sales.

(am) Concept: StatisticalClassificationCode

Market based sales.

(an) Concept: StatisticalClassificationCode

Market based sales.
(ao) Concept: StatisticalClassificationCode
Market based sales.
(ap) Concept: StatisticalClassificationCode
Market based sales.
(aq) Concept: StatisticalClassificationCode
Renewable Energy Customer Purchase Program.
(ar) Concept: EnergyReceivedThroughPowerExchanges
Deviation Power Exchange/Imbalance Charges
(as) Concept: EnergyDeliveredThroughPowerExchanges
Deviation Power Exchange/Imbalance Charges
(at) Concept: EnergyChargesOfPurchasedPower
Renewable Energy Customer Purchase Program
(au) Concept: OtherChargesOfPurchasedPower
LF Coal Strip Contract - Termination date 12/31/2023
(av) Concept: OtherChargesOfPurchasedPower
Other Charges - Energy Imbalance Market
(aw) Concept: OtherChargesOfPurchasedPower
Deviation Power Exchange/Imbalance Charges
(ax) Concept: OtherChargesOfPurchasedPower
Deviation Power Exchange/Imbalance Charges

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule or 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)	Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	Basin Electric Power	Basin Electric Power	Black Hills Power	OS		RC DC Tie	RC DC		(ah)2,037	(ai)2,037	3,292,800			3,292,800
2	(a) Black Hills Power	Black Hills Power	Black Hills Power	FNS	11	Various	Various		2,022,958	2,022,958		9,261,540	(aj)1,175,345	10,436,885
3	Basin Electric Power	Basin Electric Power	Basin Electric Power	FNO	11	Various	Various		2,193,491	2,193,491		9,142,008	900,678	10,042,686
4	(b) Cheyenne Light Fuel and Power	Cheyenne Light Fuel and Power	Cheyenne Light Fuel and Power	FNO	11	Various	Various						(93,598)	(93,598)
5	City of Gillette	Black Hills Power	City of Gillette	FNO	11	Various	Various		352,699	352,699		1,716,928	244,325	1,961,253
6	State of South Dakota	Western Area Power Administration	State of South Dakota	FNO	11	Various	Various		16,685	16,685		67,728	8,741	76,469
7	(c) Cheyenne Light Fuel and Power	Black Hills Wyoming	Cheyenne Light Fuel and Power, Basin Electric Power	LFP	7	WYODAK	SGW	152	925,012	925,012	4,978,357		677,321	5,655,678
8	MEAN	Black Hills Power	MEAN, Western Area Power Administration-LAP	LFP	7	WYODAK, WY69	SGW	30	238,063	238,063	1,023,904		76,621	1,100,525
9	Basin Electric Power	Basin Electric Power	Basin Electric Power	LFP	7	DRYFORK	RC	130	83,862	83,862	5,240,376		647,769	5,888,145
10	Basin Electric Power	Basin Electric Power	Wyoming Municipal Power Agency	LFP	7	DRYFORK	DJ	30	159,212	159,212			5,388	5,388
11	Basin Electric Power	Basin Electric Power	Basin Electric Power	SFP	7	DRYFORK	DJ		9,118	9,118		39,419	4,250	43,669
12	Basin Electric Power	Basin Electric Power	Basin Electric Power	SFP	7	DRYFORK	SGW		19,464	19,464		84,148	9,072	93,220
13	Basin Electric Power	Basin Electric Power	Basin Electric Power	SFP	7	DRYFORK	WYODAK		24	24		104	11	115
14	Basin Electric Power	Basin Electric Power	Basin Electric Power	SFP	7	DJ	WYODAK		239	239		1,033	111	1,144
15	Basin Electric Power	Basin Electric Power	Basin Electric Power	SFP	7	SGW	WYODAK		149	149		644	70	714
16	(d) Black Hills Power	Black Hills Power	Black Hills Power	SFP	7	DJ	RC		25	25		85	11	96
17	(e) Cheyenne Light Fuel and Power	Cheyenne Light Fuel and Power	Cheyenne Light Fuel and Power	SFP	7	Wyodak	DJ		120	120		795	71	866
18	Macquarie Energy LLC (MCPI01)	Macquarie Energy LLC	Macquarie Energy LLC	SFP	7	SGW	DJ		96	96		325	42	367
19	MAG Energy Solutions	MAG Energy Solutions	MAG Energy Solutions	SFP	7	RC	DJ		37,176	37,176		130,014	16,556	146,570
20	MAG Energy Solutions	MAG Energy Solutions	MAG Energy Solutions	SFP	7	RC	WYODAK		704	704		2,462	314	2,776
21	PacifiCorp	PacifiCorp	PacifiCorp	SFP	7	WSTAR	ANTELOPE		288	288		1,635	157	1,792
22	Public Service Company of Colorado (PSCMPS)	Public Service Company of CO	Public Service Company of CO	SFP	7	DJ	SGW		250	250		1,133	123	1,256
23	Public Service Company of Colorado (PSCMPS)	Public Service Company of CO	Public Service Company of CO	SFP	7	DJ	RC		700	700		3,172	343	3,515
24	Rainbow Energy Marketing Corporation	Rainbow Energy Marketing Corporation	Rainbow Energy Marketing Corporation	SFP	7	RC	DJ		73	73		308	36	344
25	Rainbow Energy Marketing Corporation	Rainbow Energy Marketing Corporation	Rainbow Energy Marketing Corporation	SFP	7	RC	WYODAK		1,440	1,440		6,082	702	6,784
26	Powerex Corp	Powerex Corp	Powerex Corp	SFP	7	RC	DJ		4,260	4,260		17,984	1,998	19,982
27	Powerex Corp	Powerex Corp	Powerex Corp	SFP	7	RC	WYODAK		1,607	1,607		6,784	754	7,538
28	TransAlta Energy Marketing U.S.Inc. (TEMU)	TransAlta Energy Marketing U.S. Inc.	TransAlta Energy Marketing U.S. Inc.	SFP	7	RC	DJ		105	105		397	48	445
29	Altop Energy (ALTOP)	Altop Energy (ALTOP)	Altop Energy (ALTOP)	NF	8	RC	DJ		10	10		238	5	243
30	Altop Energy (ALTOP)	Altop Energy (ALTOP)	Altop Energy (ALTOP)	NF	8	DJ	RC		1	1		24		24
31	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DJ	DRYFORK		2,923	2,923		2,022	1,556	3,578
32	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DJ	RC		1,893	1,893		1,309	1,008	2,317
33	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DJ	SGW		1,143	1,143		791	609	1,400
34	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DJ	SHERIDAN		112	112		77	60	137
35	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DJ	WYODAK		376	376		260	200	460
36	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DRYFORK	DJ		79,642	79,642		55,081	42,405	97,486
37	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DRYFORK	RC		6,762	6,762		4,677	3,600	8,277
38	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DRYFORK	SGW		155,961	155,961		107,863	83,040	190,903
39	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DRYFORK	SHERIDAN		245	245		169	130	299
40	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	DRYFORK	WYODAK		11,885	11,885		8,220	6,328	14,548
41	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	SGW	SHERIDAN		14	14		10	7	17

42	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	SGW	DJ		5,154	5,154		3,564	2,744	6,308
43	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	SGW	DRYFORK		88	88		61	47	108
44	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	SGW	RC		6,098	6,098		4,217	3,247	7,464
45	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	SGW	WYODAK		5,454	5,454		3,772	2,904	6,676
46	Basin Electric Power	Basin Electric Power	Basin Electric Power	NF	8	WYODAK	WYODAK		30	30		21	16	37
47	(f) Black Hills Colorado Electric	Basin Electric Power	Black Hills Colorado Electric	NF	8	DRYFORK	DJ		50	50		32	(14)	18
48	(g) Black Hills Wyoming	Black Hills Wyoming	Tristate, Pacificorp, Western Area Power Admin, Holy Cross Energy	NF		SGW	WYODAK		22	22		14	89	103
49	(h) Black Hills Wyoming	Black Hills Wyoming	Tristate	NF	8	WYODAK	DJ		2,125	2,125		1,376	8,608	9,984
50	(i) Black Hills Wyoming	Black Hills Wyoming	Black Hills Power	NF	8	WYODAK	SGW		2,910	2,910		1,884	11,788	13,672
51	(j) Black Hills Wyoming	Black Hills Wyoming	Western Area Power Authority	NF	8	WYODAK	WYODAK		20	20		13	81	94
52	(k) Black Hills Power	Pacificorp, Public Service Company of New Mexico, Public Service Company of Colorado, Black Hills Power	Black Hills Power	NF	8	DJ	RC		73,918	73,918		50,229	38,923	89,152
53	(l) Black Hills Power	Black Hills Power	Black Hills Power	NF	8	DJ	WYODAK		33	33		22	17	39
54	(m) Black Hills Power	Basin Electric Power	Black Hills Power	NF	8	DRYFORK	DJ		235	235		160	124	284
55	(n) Black Hills Power	Basin Electric Power	Black Hills Power	NF	8	DRYFORK	RC		3,451	3,451		2,345	1,817	4,162
56	(o) Black Hills Power	Basin Electric Power	Black Hills Power	NF	8	DRYFORK	SGW		603	603		410	318	728
57	(p) Black Hills Power	Pacificorp	Black Hills Power, Western Area Power Admin	NF	8	RC	DJ		25	25		17	13	30
58	(q) Black Hills Power	Black Hills Power	Western Area Power Authority, Tristate	NF	8	SGW	RC		10,202	10,202		6,933	5,372	12,305
59	(r) Black Hills Power	Black Hills Power	Basin Electric Power	NF	8	WYODAK	DJ		78,803	78,803		53,549	41,495	95,044
60	(s) Black Hills Power	Black Hills Power	Basin Electric Power	NF	8	WYODAK	DRYFORK		3,360	3,360		2,283	1,769	4,052
61	(t) Black Hills Power	Black Hills Power	Basin Electric Power	NF	8	WYODAK	RC		10,241	10,241		6,959	5,393	12,352
62	(u) Black Hills Power	Basin Electric Power	Black Hills Power	NF	8	WYODAK	SGW		33,064	33,064		22,468	17,410	39,878
63	(v) Black Hills Power	Pacificorp, Public Service Company of New Mexico, Public Service Company of Colorado, Black Hills Power	Black Hills Power	NF	8	WYODAK	SHERIDAN		5,434	5,434		3,693	2,861	6,554
64	(w) Black Hills Power	Black Hills Power	Western Area Power Administration, Holy Cross	NF	8	WYODAK	WYODAK		1,368	1,368		930	720	1,650
65	(x) Cheyenne Light Fuel and Power	Pacificorp	Black Hills Power	NF	8	DJ	RC		10	10		6	5	11
66	(y) Cheyenne Light Fuel and Power	Black Hills Power	Black Hills Power	NF	8	DRYFORK	SGW		3,103	3,103		1,789	1,651	3,440
67	(z) Cheyenne Light Fuel and Power	Black Hills Power	Black Hills Power	NF	8	DRYFORK	RC		60	60		35	32	67
68	(aa) Cheyenne Light Fuel and Power	Black Hills Power	Black Hills Power	NF	8	DRYFORK	DJ		1,930	1,930		1,113	1,027	2,140
69	(ab) Cheyenne Light Fuel and Power	Pacificorp	Black Hills Power	NF	8	RC	DJ		1,200	1,200		692	639	1,331
70	(ac) Cheyenne Light Fuel and Power	Black Hills Power	Black Hills Power	NF	8	RC	SGW		1,003	1,003		578	534	1,112
71	(ad) Cheyenne Light Fuel and Power	Black Hills Power	Black Hills Power	NF	8	SGW	RC		10	10		6	5	11
72	(ae) Cheyenne Light Fuel and Power	Black Hills Power	Black Hills Power	NF	8	WYODAK	DJ		1,080	1,080		623	575	1,198
73	(af) Cheyenne Light Fuel and Power	Black Hills Power	Black Hills Power	NF	8	WYODAK	SGW		9,577	9,577		5,522	5,096	10,618
74	(ag) Cheyenne Light Fuel and Power	Black Hills Power	Black Hills Power	NF	8	WYODAK	WYODAK		1,200	1,200		692	639	1,331
75	Shell Energy North America (CORP)	Shell Energy North America	Shell Energy North America	NF	8	DJ	RC		520	520		505	172	677
76	Shell Energy North America (CORP)	Shell Energy North America	Shell Energy North America	NF	8	RC	DJ		1,445	1,445		1,404	479	1,883
77	CP Energy Marketing (US) Inc (EEMU)	CP Energy Marketing (US) Inc	CP Energy Marketing (US) Inc	NF	8	SGW	DJ		395	395		251	38	289
78	Dynasty Power Inc.	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	DJ	RC		770	770		741	385	1,126
79	Dynasty Power Inc.	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	DJ	SGW		240	240		231	120	351
80	Dynasty Power Inc.	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	RC	DJ		24,206	24,206		23,307	12,093	35,400
81	Dynasty Power Inc.	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	RC	SGW		7,197	7,197		6,930	3,596	10,526
82	Dynasty Power Inc.	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	SGW	DJ		7,833	7,833		7,542	3,913	11,455
83	Dynasty Power Inc.	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	SGW	RC		190	190		183	95	278
84	Dynasty Power Inc.	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	DRYFORK	RC		543	543		523	271	794
85	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	DJ	RC		699	699		443	351	794
86	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	DJ	SHERIDAN		9,874	9,874		6,255	4,953	11,208
87	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	DJ	SGW		1,370	1,370		868	687	1,555
88	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	RC	DJ		15,403	15,403		9,758	7,726	17,484
89	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	RC	SGW		115	115		73	58	131
90	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	RC	SHERIDAN		365	365		231	183	414
91	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	SGW	DJ		1,839	1,839		1,165	922	2,087
92	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	SGW	RC		365	365		231	183	414

93	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	SGW	SHERIDAN		100	100		63	50	113
94	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	WYODAK	WYODAK		20	20		13	10	23
95	Macquarie Energy LLC (MCPI01)	Macquarie Energy LLC	Macquarie Energy LLC	NF	8	RC	DJ		8,177	8,177		9,145	3,947	13,092
96	Macquarie Energy LLC (MCPI01)	Macquarie Energy LLC	Macquarie Energy LLC	NF	8	SGW	DJ		3,881	3,881		4,340	1,873	6,213
97	MAG Energy Solutions	MAG Energy Solutions	MAG Energy Solutions	NF	8	DJ	RC		4	4		3	2	5
98	MAG Energy Solutions	MAG Energy Solutions	MAG Energy Solutions	NF	8	DJ	WYODAK		912	912		577	342	919
99	MAG Energy Solutions	MAG Energy Solutions	MAG Energy Solutions	NF	8	RC	DJ		14,352	14,352		9,086	5,379	14,465
100	MAG Energy Solutions	MAG Energy Solutions	MAG Energy Solutions	NF	8	WYODAK	RC		1	1		1		1
101	MAG Energy Solutions	MAG Energy Solutions	MAG Energy Solutions	NF	8	RC	WYODAK		879	879		556	329	885
102	MAG Energy Solutions	MAG Energy Solutions	MAG Energy Solutions	NF	8	WYODAK	DJ		2	2		1	1	2
103	Mercuria Energy America, LLC (MEAI01)	Mercuria Energy America, LLC	Mercuria Energy America, LLC	NF	8	DJ	SGW		247	247		157	135	292
104	Mercuria Energy America, LLC (MEAI01)	Mercuria Energy America, LLC	Mercuria Energy America, LLC	NF	8	DJ	RC		2,950	2,950		1,875	1,616	3,491
105	Mercuria Energy America, LLC (MEAI01)	Mercuria Energy America, LLC	Mercuria Energy America, LLC	NF	8	RC	DJ		10,494	10,494		6,670	5,749	12,419
106	Mercuria Energy America, LLC (MEAI01)	Mercuria Energy America, LLC	Mercuria Energy America, LLC	NF	8	RC	SGW		52	52		33	28	61
107	Mercuria Energy America, LLC (MEAI01)	Mercuria Energy America, LLC	Mercuria Energy America, LLC	NF	8	RC	SHERIDAN		300	300		191	164	355
108	Mercuria Energy America, LLC (MEAI01)	Mercuria Energy America, LLC	Mercuria Energy America, LLC	NF	8	RC	WYODAK		6,062	6,062		3,853	3,321	7,174
109	Mercuria Energy America, LLC (MEAI01)	Mercuria Energy America, LLC	Mercuria Energy America, LLC	NF	8	SGW	RC		502	502		319	275	594
110	Mercuria Energy America, LLC (MEAI01)	Mercuria Energy America, LLC	Mercuria Energy America, LLC	NF	8	SGW	WYODAK		50	50		32	27	59
111	Mercuria Energy America, LLC (MEAI01)	Mercuria Energy America, LLC	Mercuria Energy America, LLC	NF	8	SGW	DJ		103	103		65	56	121
112	Mercuria Energy America, LLC (MEAI01)	Mercuria Energy America, LLC	Mercuria Energy America, LLC	NF	8	WYODAK	SHERIDAN		400	400		254	219	473
113	Pacificorp	Pacificorp	Black Hills Power, Pacificorp	NF	8	WSTAR	DJ		1	1		1		1
114	Pacificorp	Pacificorp	Pacificorp	NF	8	WYODAK	DJ		3,250	3,250		2,507	1,277	3,784
115	Pacificorp	Pacificorp	Pacificorp	NF	8	WYODAK	WSTAR		289	289		223	114	337
116	Powerex Corp	Powerex Corp	Powerex Corp	NF	8	DJ	WYODAK		5,557	5,557		3,984	2,927	6,911
117	Powerex Corp	Powerex Corp	Powerex Corp	NF	8	RC	DJ		20,956	20,956		15,025	11,038	26,063
118	Powerex Corp	Powerex Corp	Powerex Corp	NF	8	RC	WYODAK		19,496	19,496		13,978	10,269	24,247
119	Powerex Corp	Powerex Corp	Powerex Corp	NF	8	WYODAK	DJ		38	38		27	20	47
120	Public Service Company of Colorado (PSCMPS)	Public Service Company of Colorado	Public Service Company of Colorado	NF	8	DJ	RC		3,522	3,522		3,411	1,945	5,356
121	Public Service Company of Colorado (PSCMPS)	Public Service Company of Colorado	Public Service Company of Colorado	NF	8	SGW	RC		200	200		194	110	304
122	Public Service Company of Colorado (PSCMPS)	Public Service Company of Colorado	Public Service Company of Colorado	NF	8	RC	SGW		641	641		621	354	975
123	Public Service Company of Colorado (PSCMPS)	Public Service Company of Colorado	Public Service Company of Colorado	NF	8	RC	DJ		7,143	7,143		6,919	3,944	10,863
124	Rainbow Energy Marketing Corporation (REMC)	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	DJ	RC		6,383	6,383		4,179	3,147	7,326
125	Rainbow Energy Marketing Corporation (REMC)	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	DJ	SGW		120	120		79	59	138
126	Rainbow Energy Marketing Corporation (REMC)	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	DRYFORK	DJ		99	99		65	49	114
127	Rainbow Energy Marketing Corporation (REMC)	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	DRYFORK	RC		70	70		46	35	81
128	Rainbow Energy Marketing Corporation (REMC)	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	RC	DJ		22,477	22,477		14,716	11,082	25,798
129	Rainbow Energy Marketing Corporation (REMC)	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	RC	SGW		7,395	7,395		4,841	3,646	8,487
130	Rainbow Energy Marketing Corporation (REMC)	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	SGW	DJ		792	792		518	390	908
131	Rainbow Energy Marketing Corporation (REMC)	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	SGW	RC		60	60		39	30	69
132	Rainbow Energy Marketing Corporation (REMC)	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	SGW	ANTELOPE		138	138		90	68	158
133	Rainbow Energy Marketing Corporation (REMC)	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	SGW	WYODAK		1,224	1,224		801	603	1,404
134	Rainbow Energy Marketing Corporation (REMC)	Rainbow Energy Marketing Corporation, Basin Electric Power	Rainbow Energy Marketing Corporation, Basin Electric Power	NF	8	WYODAK	RC		1,000	1,000		65	49	114
135	The Energy Authority (TEA)	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	DJ	RC		315	315		227	142	369
136	The Energy Authority (TEA)	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	RC	DJ		2,771	2,771		1,997	1,245	3,242
137	The Energy Authority (TEA)	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	RC	SGW		320	320		231	144	375
138	The Energy Authority (TEA)	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	RC	WYODAK		109	109		79	49	128
139	The Energy Authority (TEA)	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	RC	WSTAR		550	550		396	247	643
140	The Energy Authority (TEA)	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	WYODAK	DJ		84	84		61	38	99

141	The Energy Authority (TEA)	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	WYODAK	WSTAR		196	196		141	88	229
142	The Energy Authority (TEA)	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	WSTAR	DJ		746	746		538	335	873
143	The Energy Authority (TEA)	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	WYODAK	SGW		4	4		3	2	5
144	TEC Energy Inc (TECX)	TEC Energy Inc	TEC Energy Inc	NF	8	RC	DJ		60	60		51	36	87
145	TransAlta Energy Marketing U.S.Inc. (TEMU)	TransAlta Energy Marketing U.S.Inc.	TransAlta Energy Marketing U.S.Inc.	NF	8	DJ	RC		350	350		228	175	403
146	TransAlta Energy Marketing U.S.Inc. (TEMU)	TransAlta Energy Marketing U.S.Inc.	TransAlta Energy Marketing U.S.Inc.	NF	8	RC	DJ		14,308	14,308		9,318	7,138	16,456
147	TransAlta Energy Marketing U.S.Inc. (TEMU)	TransAlta Energy Marketing U.S.Inc.	TransAlta Energy Marketing U.S.Inc.	NF	8	RC	SGW		416	416		271	208	479
148	TransAlta Energy Marketing U.S.Inc. (TEMU)	TransAlta Energy Marketing U.S.Inc.	TransAlta Energy Marketing U.S.Inc.	NF	8	RC	WYODAK		120	120		78	60	138
149	TransAlta Energy Marketing U.S.Inc. (TEMU)	TransAlta Energy Marketing U.S.Inc.	TransAlta Energy Marketing U.S.Inc.	NF	8	SGW	DJ		94	94		60	47	107
150	TransAlta Energy Marketing U.S.Inc. (TEMU)	TransAlta Energy Marketing U.S.Inc.	TransAlta Energy Marketing U.S.Inc.	NF	8	DRYFORK	SGW		71	71		46	35	81
151	Tenaska Power Services Co	Tenaska Power Services Co	Tenaska	NF	8	RC	DJ		545	545		410	261	671
152	WestConnect	Altop Energy (ALTOP)	Altop Energy (ALTOP)	NF	8	DJ	RC		1	1		1	1	2
153	WestConnect	CP Energy Marketing (US) Inc. (EEMU)	CP Energy Marketing (US) Inc. (EEMU)	NF	8	DJ	RC		50	50		22	64	86
154	WestConnect	CP Energy Marketing (US) Inc. (EEMU)	CP Energy Marketing (US) Inc. (EEMU)	NF	8	SGW	RC		45	45		20	58	78
155	WestConnect	Dynasty Power Inc.	Dynasty Power Inc.	NF	8	DJ	SGW		1,392	1,392		847	703	1,550
156	WestConnect	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	SGW	DJ		185	185		90	224	314
157	WestConnect	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	RC	DJ		250	250		122	303	425
158	WestConnect	Guzman Energy LLC (GPM)	Guzman Energy LLC (GPM)	NF	8	RC	SGW		420	420		205	510	715
159	WestConnect	MAG Energy Solutions	MAG Energy Solutions	NF	8	RC	DJ		373	373		687	355	1,042
160	WestConnect	Mercuria Energy America, LLC (MEAI01)	Mercuria Energy America, LLC (MEAI01)	NF	8	RC	DJ		2	2		1	4	5
161	WestConnect	Powerex Corp.	Powerex Corp.	NF	8	RC	DJ		10	10		6	11	17
162	WestConnect	Powerex Corp.	Powerex Corp.	NF	8	RC	SGW		31	31		18	35	53
163	WestConnect	Powerex Corp.	Powerex Corp.	NF	8	SGW	DJ		119	119		69	136	205
164	WestConnect	Powerex Corp.	Powerex Corp.	NF	8	WYODAK	SGW		396	396		229	453	682
165	WestConnect	Rainbow Energy Marketing Corporation (REMC)	Rainbow Energy Marketing Corporation	NF	8	DJ	WYODAK		70	70		35	67	102
166	WestConnect	Rainbow Energy Marketing Corporation (REMC)	Rainbow Energy Marketing Corporation	NF	8	RC	DJ		521	521		258	496	754
167	WestConnect	Rainbow Energy Marketing Corporation (REMC)	Rainbow Energy Marketing Corporation	NF	8	RC	SGW		944	944		468	899	1,367
168	WestConnect	Shell Energy North America (CORP)	Shell Energy North America	NF	8	RC	DJ		1,955	1,955		1,105	1,469	2,574
169	WestConnect	Shell Energy North America (CORP)	Shell Energy North America	NF	8	RC	SGW		474	474		268	356	624
170	WestConnect	SociVolta Inc. (SVI)	SociVolta Inc. (SVI)	NF	8	SGW	RC		1	1		1	1	2
171	WestConnect	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	RC	DJ		1,522	1,522		991	1,122	2,113
172	WestConnect	The Energy Authority (TEA)	The Energy Authority (TEA)	NF	8	RC	SGW		643	643		419	474	893
173	WestConnect	TransAlta Energy Marketing U.S.Inc.	TransAlta Energy Marketing U.S.Inc.	NF	8	SGW	DJ		75	75		32	163	195
35	TOTAL							342	6,846,931	6,846,931	14,535,437	21,031,710	4,101,210	39,668,357

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(b) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(c) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(d) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(e) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(f) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(g) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(h) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(i) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(j) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(k) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(l) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(m) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(n) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(o) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(p) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(q) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(r) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(s) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(t) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(u) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(v) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(w) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(x) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(y) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(z) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(aa) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(ab) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(ac) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(ad) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(ae) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(af) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(ag) Concept: PaymentByCompanyOrPublicAuthority

Affiliate Transaction

(ah) Concept: TransmissionOfElectricityForOthersEnergyReceived

Losses Received on RC DC Tie

(ai) Concept: TransmissionOfElectricityForOthersEnergyDelivered

Losses Received on RC DC Tie

(aj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Other Charges in Column (m) are Ancillary Charges

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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					
40	TOTAL				

FERC FORM NO. 1 (REV 03-07)

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
   FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Powder River Energy	NF	769	769				
2	PacifiCorp	FNS	303,043	303,043		2,057,718		2,057,718
3	PacifiCorp	LFP	438,000	438,000	1,968,413			1,968,413
4	PacifiCorp	NF	3,446,158	3,446,158		1,236,842		1,236,842
5	PacifiCorp	NF						
6	Arizona Power	NF						
7	Basin Electric	NF	16,707	16,707		24,965		24,965
8	Colorado River Storage	NF	6,106	6,106		14,651		14,651
9	Deseret	NF						
10	Idaho Power Co	NF						
11	Midwest Independent Trans	NF						
12	Midwest ISO	NF						
13	Northwestern Energy	SFP						
14	Nevada Power	NF						
15	Public Service Company of Colorado	NF	935	935		8,015		8,015
16	Public Service Company of New Mexico	NF						
17	Southwest Power Pool	NF	50,177	50,177		476,899		476,899
18	Tri-State Generation	NF						
19	Western Area Power - MAPP	NF				587		587
20	[(a)] Western Area Power	OS	215	215				
21	Western Area Power Loveland	NF	14,114	14,114				
22	Transalta	NF				(159)		(159)
23	[(b)] Cheyenne Light Fuel and Power	NF						
24	[(c)] Black Hills Colorado Electric	NF						
25	[(d)] Black Hills Wyoming	NF						
26	Western Area Power East	NF						
27	Western Area Power Upper Great Plains	OS						
28	Western Area Power	OS				238,556		238,556
29	Western Area Power	SFP						
30	[(e)] Black Hills Basin Electric Common Use System	LFP	41,303	41,303	[(m)]2,850,753			2,850,753
31	[(f)] Black Hills Basin Electric Common Use System	NF						
32	[(g)] Black Hills Colorado Electric	OS						
33	[(h)] Cheyenne Light Fuel and Power	OS						
34	Transmission Accruals	OS				(525,117)		(525,117)
35	Western Area Power Administration	OS					[(n)]1,713,798	1,713,798
36	Western Area Power Administration	NF						
37	Western Area Power Administration	NF						
38	[(i)] Black Hills Basin Electric Common Use System	FNS	2,022,958	2,022,958		14,777,067	[(o)]1,855,698	16,632,765
39	[(j)] Black Hills Basin Electric Common Use System	LFP						
40	[(k)] Black Hills Basin Electric Common Use System	NF	220,738	220,738		220,738	[(p)]196,331	417,069
41	[(l)] Black Hills Basin Electric Common Use System	SFP						
	TOTAL		6,561,223	6,561,223	4,819,166	18,530,762	3,765,827	27,115,755

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers
Oasis and Etagging costs associated with WAPA Contract
(b) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers
Affiliate reimbursement to Black Hills Power for transmission expense incurred per Agreements.
(c) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers
Affiliate reimbursement to Black Hills Power for transmission expense incurred per Agreements
(d) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers
Affiliate reimbursement to Black Hills Power for transmission expense incurred per Agreements
(e) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers
Affiliate transactions - BHP is a joint owner of the BHBE Transmission System; Amounts shown are charges from BHBE. Amounts included in Other Charges represent ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assesments.
(f) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers
Affiliate transactions - BHP is a joint owner of the BHBE Transmission System; Amounts shown are charges from BHBE. Amounts included in Other Charges represent ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assesments.
(g) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers
Affiliate reimbursement to Black Hills Power for transmission expense incurred per Agreements
(h) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers
Affiliate reimbursement to Black Hills Power for transmission expense incurred per Agreements
(i) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers
Affiliate transactions - BHP is a joint owner of the BHBE Transmission System; Amounts shown are charges from BHBE. Amounts included in Other Charges represent ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assesments.
(j) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers
Affiliate transactions - BHP is a joint owner of the BHBE Transmission System; Amounts shown are charges from BHBE. Amounts included in Other Charges represent ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assesments.
(k) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers
Affiliate transactions - BHP is a joint owner of the BHBE Transmission System; Amounts shown are charges from BHBE. Amounts included in Other Charges represent ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assesments.
(l) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers
Affiliate transactions - BHP is a joint owner of the BHBE Transmission System; Amounts shown are charges from BHBE. Amounts included in Other Charges represent ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assesments.
(m) Concept: DemandChargesTransmissionOfElectricityByOthers
Rapid City DC Tie Transactions
(n) Concept: OtherChargesTransmissionOfElectricityByOthers
Regulation costs paid to WAPA
(o) Concept: OtherChargesTransmissionOfElectricityByOthers
Affiliate transactions - BHP is a joint owner of the BHBE Transmission System; Amounts shown are charges from BHBE. Amounts included in Other Charges represent ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assesments.
(p) Concept: OtherChargesTransmissionOfElectricityByOthers
Affiliate transactions - BHP is a joint owner of the BHBE Transmission System; Amounts shown are charges from BHBE. Amounts included in Other Charges represent ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assesments.

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	29,272
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	Directors' Fees	173,438
7	Bank Fees	213,131
8	Travel	15,489
9	Amortization of Deferred Financing Costs	117,367
10	Business Promotions	30,718
11	Consulting Fees	11,605
12	Economic Development Costs	71,080
13	Software Service	9,247
14	Sponsorships	17,250
15	Miscellaneous Other	61,409
46	TOTAL	750,006

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

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

1. Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
   Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
   In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
   For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant					
2	Steam Production Plant	12,895,363			887,218	13,782,581
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	7,758,857	31,627			7,790,484
7	Transmission Plant	6,766,158				6,766,158
8	Distribution Plant	14,194,293				14,194,293
9	Regional Transmission and Market Operation					
10	General Plant	8,389,835		187,562		8,577,397
11	Common Plant-Electric					
12	TOTAL	50,004,506	31,627	187,562	887,218	(a)51,110,913

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	Steam Production Plant						
13	Osage	816	60 years	22%	12.07%		
14	Wyodak	121,588	58 years	13%	2.86%		24 years
15	Neil Simpson II	197,724	60 years	14%	2.9%		28 years
16	Wygen III	144,127	60 years	13%	2.64%		40 years
17	SUBTOTAL STEAM PROD	464,255					
18	Other Production Plant						
19	Lange CT	32,910	44 years	5%	2.29%		30 years
20	Neil Simpson I CT	33,800	44 years	5%	2.56%		28 years
21	Ben French CT	23,183	44 years	13%	2.61%		14 years
22	Ben French Diesel CT	2,333	45 years	22%	5.06%		7 years
23	Cheyenne Prairie Generating Station	114,037	40 years	4%	2.98%		42 years
24	Corriedale Wind Farm	49,347	25 years	0%	4.28%		25 years
25	SUBTOTAL OTHER PROD	255,610					
26	(b) Transmission Plant						
27	(352)Structures and Im	2,044	50 years	10%	1.83%		40 years
28	(353)Station Equipment	76,414	42 years	5%	2.13%		36 years
29	(354)Towers and Fixtures	865	60 years	20%	1.74%		56 years
30	(355)Poles and Fixtures	115,278	55 years	30%	2.74%		38 years
31	(356)Overhead Conductors and Devices	93,326	60 years	20%	2.05%		45 years
32	(359)Roads & Trails	7	60 years		1.72%		32 years
33	SUBTOTAL TRANSMISSION	287,934					
34	Distribution Plant						
35	(361)Structures and Imrovements	2,325	40 years	5%	2.45%		33 years
36	(362)Station Equipment	115,228	45 years	10%	2.27%		34 years
37	(364)Poles, Towers & Fixtures	119,332	50 years	70%	3.64%		37 years
38	(365)Overhead Conductor	68,867	50 years	20%	2.26%		39 years
39	(366)Underground Conduit	25,935	37 years	5%	2.81%		33 years
40	(367)Underground Conductors and Devices	79,619	40 years	5%	2.32%		30 years
41	(368)Line Transformers	66,846	36 years	0%	2.41%		27 years
42	(369)Services	40,755	62 years	50%	2.29%		51 years

43	(370)Meters	11,795	21 years	0%	5.23%		18 years
44	(371)Installation on Customer Premises	3,224	30 years	10%	3.22%		22 years
45	(373)Street Lighting	2,994	25 years	15%	3.96%		17 years
46	SUBTOTAL DISTRIBUTION	536,920					
47	(c) General Plant						
48	(390)Structures and Improvements	85,561	40 years	10%	1.67%		32 years
49	(391)Office Furniture and Equipment	15,419	10 years	0%	13.82%		6 years
50	(392)Transportation Equipment	26,980	13 years	10%	3.45%		11 years
51	(393)Stores Equipment	167	20 years	0%	9.32%		5 years
52	(394)Tools, Shop, & Garage Equipment	3,827	25 years	0%	3.33%		17 years
53	(395)Laboratory Equipment	771	25 years	0%	7.46%		13 years
54	(396)Power Operated Equipment	4,079	30 years	20%	1.28%		27 years
55	(397)Communication Equipment	6,752	20 years	0%	5.63%		14 years
56	(398)Miscellaneous Equipment	1,546	20 years	0%	5.8%		13 years
57	SUBTOTAL GENERAL	145,102					
58	TOTAL	1,689,821					

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DepreciationAndAmortization

Note: Amounts footnoted are based upon FERC-approved rates

Line No.	Functional Classification	Depreciation Expense (Account 403)	Depreciation Expense for Asset Retirement Costs (Account 403.1)	Amortization of Limited Term Electric Plant (Account 404)	Amortization of Other Electric Plant (Acc 405)	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1	Intangible Plant					
2	Steam Production Plant	12,895,363			887,218	13,782,581
3	Nuclear Production Plant					
4	Hydraulic Production Plant - Conventional					
5	Hydraulic Production Plant - Pumped Storage					
6	Other Production Plant	7,758,857	31,627			7,790,484
7	Transmission Plant	6,490,043				6,490,043
8	Distribution Plant	14,194,293				14,194,293
9	Regional Transmission and Market Operation					
10	General Plant	11,942,328		187,562		12,129,890
11	Common Plant - Electric					
12	Total	53,280,885	31,627	187,562	887,218	54,387,292

(b) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

Note: Amounts footnoted are based upon FERC-approved rates

Line No.	Account No.	Depreciable Plant Base (in Thousands)	Estimated Avg. Service Life	Net Salvage (Percent)	Applied Depr. Rates (Percent)	Mortality Curve Type	Average Remaining
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
26	**Transmission Plant**						
27	(352) Structures and Improvements	2,044	45 years	10%	2.39%		35 years
28	(353) Station Equipment	76,414	35 years		2.66%		26 years
29	(354) Towers and Fixtures	865	55 years	15%	2.04%		49 years
30	(355) Poles and Fixtures	115,278	55 years	25%	2.22%		27 years
31	(356) Overhead Conductors and Devices	93,326	55 years	15%	2.04%		32 years
32	(359) Roads & Trails	7	50 years		1.95%		6 years
33	**SUBTOTAL TRANSMISSION**	**287,934**					

(c) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

Note: Amounts footnoted are based upon FERC-approved rates

Line No.	Account No.	Depreciable Plant Base (in Thousands)	Estimated Avg. Service Life	Net Salvage (Percent)	Applied Depr. Rates (Percent)	Mortality Curve Type	Average Remaining Life
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
47	**General Plant**						
48	(390) Structures and Improvements	85,561	30 years	10%	4.73%		12 years
49	(391) Office Furniture and Equipment	15,419	10 years		10.56%		
50	(392) Transportation Equipment	26,980	10 years		9.06%		3 years
51	(393) Stores Equipment	167	30 years		4.23%		6 years
52	(394) Tools, Shop, & Garage Equipment	3,827	30 years		4.23%		18 years
53	(395) Lab Equipment	771	50 years		3.06%		35 years
54	(396) Power Operated Equipment	4,079	30 years		4.23%		22 years
55	(397) Communication Equipment	6,752	30 years		4.39%		17 years
56	(398) Miscellaneous Equipment	1,546	20 years		5.81%		
57	**SUBTOTAL GENERAL**	**145,102**					

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

						EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO						
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	FERC Assessment	468,323		468,323		Reg Serv.	928					
2	Rate Case Expenses/Other				66,650					588/928	66,650	
3	Public Utilities Commission Assessments	362,586	103,696	466,282		Reg Serv.	588					
46	TOTAL	830,909	103,696	934,605	66,650						66,650	

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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							

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	4,727,297		4,727,297
4	Transmission	1,821,252		1,821,252
5	Regional Market			0
6	Distribution	2,967,728		2,967,728
7	Customer Accounts	845,045		845,045
8	Customer Service and Informational	343,458		343,458
9	Sales	1,712		1,712
10	Administrative and General	15,856,884		15,856,884
11	TOTAL Operation (Enter Total of lines 3 thru 10)	26,563,376		26,563,376
12	Maintenance			
13	Production	2,601,285		2,601,285
14	Transmission	47,513		47,513
15	Regional Market			
16	Distribution	1,207,017		1,207,017
17	Administrative and General	64,418		64,418
18	TOTAL Maintenance (Total of lines 13 thru 17)	3,920,233		3,920,233
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	7,328,582		7,328,582
21	Transmission (Enter Total of lines 4 and 14)	1,868,765		1,868,765
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	4,174,745		4,174,745
24	Customer Accounts (Transcribe from line 7)	845,045		845,045
25	Customer Service and Informational (Transcribe from line 8)	343,458		343,458
26	Sales (Transcribe from line 9)	1,712		1,712
27	Administrative and General (Enter Total of lines 10 and 17)	15,921,302		15,921,302
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	30,483,609		30,483,609
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			

58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance	343,872		343,873
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	30,827,481		30,827,481
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	3,247,490		3,247,490
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	3,247,490		3,247,490
72	Plant Removal (By Utility Departments)			
73	Electric Plant	144,959		144,959
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	144,959		144,959
77	Other Accounts (Specify, provide details in footnote):			
78	Customer Accounts Receivable (142)	22,587		22,587
79	Accounts Receivable Third Party Billing (143)	(43,299)		(43,299)
80	Stores Expense Undistributed (163)	823,809		823,809
81	Clearing Accounts (184)	2,895,986		2,895,986
82	Misc Current and Accrued Liabilities (242)	(486,349)		(486,349)
83	Preliminary Surveys and Investigation Charges (183)	78,811		78,811
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,291,545		3,291,545
96	TOTAL SALARIES AND WAGES	37,511,475		37,511,475

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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.

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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)	0	[a]256,644	504,300	1,024,264
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	0	(455,167)	(1,905,344)	(2,278,361)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
46	TOTAL	0	(198,523)	(1,401,044)	(1,254,097)

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

In September 2022, Black Hills Power agreed to join Southwest Power Pools Western Energy Imbalance Service (WEIS) Market. In April 2023, Black Hills Power integrated into the WEIS Market and expects to continue studying long-term solutions for joining or developing an organized wholesale market. The expansion allows the utility to participate in a real-time market.

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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	3,746,193	KW/M	703,234	12,555,386	KW/M	2,363,716
2	Reactive Supply and Voltage	3,746,193	KW/M	1,325,764	12,555,386	KW/M	1,896,728
3	Regulation and Frequency Response	5,149	MW	0	0		0
4	Energy Imbalance	0		0	0		0
5	Operating Reserve - Spinning	0		0	0		0
6	Operating Reserve - Supplement	0		0	0		0
7	Other	[a]2022959	MWH	[b]180,284	5,991,982	MWH	534,164
8	Total (Lines 1 thru 7)	9,520,494		2,209,282	31,102,754		4,794,608

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnits
FERC Annual Charge Assessment
(b) Concept: AncillaryServicesPurchasedAmount
FERC Annual Charge Assessment

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: Common Use System (CUS)									
1	January	879	28	18	304	376	342		31	229
2	February	865	23	21	309	372	342			240
3	March	819	13	9	290	368	342			168
4	Total for Quarter 1				903	1,116	1,026		31	637
5	April	744	21	21	232	330	342			105
6	May	806	29	18	225	256	342			5
7	June	904	19	18	314	312	332		137	45
8	Total for Quarter 2				771	898	1,016		137	155
9	July	926	30	15	306	314	347			346
10	August	948	18	15	362	352	347			140
11	September	1,008	3	17	333	344	347			76
12	Total for Quarter 3				1,001	1,010	1,041			562
13	October	906	27	18	272	339	347			112
14	November	874	2	9	257	320	347			137
15	December	881	28	10	259	333	347			89
16	Total for Quarter 4				788	992	1,041			338
17	Total				3,463	4,016	4,124		168	1,692

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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: Enter System									
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2023-12-31	Year/Period of Report End of: 2023/ 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)	1,839,952
3	Steam	1,519,958	23	Requirements Sales for Resale (See instruction 4, page 311.)	146,985
4	Nuclear	0	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	568,664
5	Hydro-Conventional	0	25	Energy Furnished Without Charge	0
6	Hydro-Pumped Storage	0	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	0
7	Other	372,152	27	Total Energy Losses	(16,775)
8	Less Energy for Pumping	0	27.1	Total Energy Stored	0
9	Net Generation (Enter Total of lines 3 through 8)	1,892,110	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	2,538,826
10	Purchases (other than for Energy Storage)	825,855			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	153,079			
13	Delivered	332,218			
14	Net Exchanges (Line 12 minus line 13)	(179,139)			
15	Transmission For Other (Wheeling)				
16	Received	6,846,931			
17	Delivered	6,846,931			
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses	0			
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	2,538,826			

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

MONTHLY PEAKS AND OUTPUT

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

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: Black Hills Power					
29	January	272,814	52,859	337	30	8
30	February	255,606	41,098	321	22	19
31	March	291,138	70,432	300	8	9
32	April	216,154	37,630	257	21	10
33	May	155,567	24,437	271	23	16
34	June	164,291	24,383	314	19	18
35	July	193,580	32,367	378	25	18
36	August	193,641	29,340	369	18	16
37	September	159,369	34,868	338	2	16
38	October	188,061	59,411	289	27	9
39	November	201,507	54,035	273	24	18
40	December	247,098	57,732	287	13	8
41	Total	2,538,826	518,592			

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: Ben French Diesel	Plant Name:	Plant Name: Ben French Station	Plant Name:	Plant Name: [a] Cheyenne Prairie Generating Station	Plant Name: Lange CT	Plant Name: Neil Simpson CT #1	Plant Name: Neil Simpson Unit 2	Plant Name: [b] Wygen 3	Plant Name: [c] Wyodak
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Internal Combustion		Gas Turbine		Combined Cycle Operation	Gas Turbine	Gas Turbine	Steam	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional		Conventional		Conventional	Conventional	Conventional	Conventional	Conventional	Conventional
3	Year Originally Constructed	1965		1977		2014	2002	2000	1995	2010	1978
4	Year Last Unit was Installed	1965		1979		2014	2002	2000	1995	2010	1978
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	10		100		58	40	40	90	60.3	80.5
6	Net Peak Demand on Plant - MW (60 minutes)	10		98		55	38	37	84	54	69
7	Plant Hours Connected to Load	811		206		5,680	1,477	2,739	8,156	8,368	7,722
8	Net Continuous Plant Capability (Megawatts)	10		80		60	38	37	80	54	67
9	When Not Limited by Condenser Water								80	54	67
10	When Limited by Condenser Water								80	54	67
11	Average Number of Employees					18			40	36	110
12	Net Generation, Exclusive of Plant Use - kWh	(395,520)		3,479,632		257,529,500	38,170,020	73,088,000	612,636,000	394,948,000	494,371,000
13	Cost of Plant: Land and Land Rights			7,554		2,355,715	2,705		117,401		109,191
14	Structures and Improvements			1,458,009		5,832,297	614,225	344,085	33,724,889	10,850,643	9,136,528
15	Equipment Costs	2,313,021		21,376,856		111,286,878	31,311,615	33,251,678	154,726,400	131,340,549	112,047,824
16	Asset Retirement Costs										
17	Total cost (total 13 thru 20)	2,313,021		22,842,419		119,474,890	31,928,545	33,595,763	188,568,690	142,191,192	121,293,543
18	Cost per KW of Installed Capacity (line 17/5) Including	231.302		228.424		2,059.912	798.214	839.894	2,095.208	2,358.063	1,506.752
19	Production Expenses: Oper, Supv, & Engr	11,029		212,516		585,713	84,194	106,225	320,663	195,095	1,020,824
20	Fuel	5,614		563,674		9,609,531	1,327,630	3,413,917	9,889,738	6,344,916	7,009,926
21	Coolants and Water (Nuclear Plants Only)										
22	Steam Expenses								805,525	420,529	281,777
23	Steam From Other Sources										
24	Steam Transferred (Cr)										
25	Electric Expenses	17,311		86,377		730,742	117,113	260,178	365,655	242,874	
26	Misc Steam (or Nuclear) Power Expenses	131		131			131		607,509	337,594	549,334
27	Rents					782,071	584,574	880,315	1,227,619	2,118,318	
28	Allowances										
29	Maintenance Supervision and Engineering	238		4,706		5,406	1,192		538,180	252,981	23,951
30	Maintenance of Structures					807		621	377,361	302,280	
31	Maintenance of Boiler (or reactor) Plant								2,726,297	1,343,541	1,143,742
32	Maintenance of Electric Plant	64,227		356,158		731,788	457,693	157,470	683,073	367,417	226,456
33	Maintenance of Misc Steam (or Nuclear) Plant								19,407	11,507	2,287
34	Total Production Expenses	98,550		1,223,562		12,446,058	2,572,527	4,818,726	17,561,027	11,937,052	10,258,297
35	Expenses per Net kWh			0.3516		0.0483	0.0674	0.0659	0.0287	0.0302	0.0208

35	**Plant Name**				Cheyenne Prairie Generating Station	Lange CT	Neil Simpson CT #1	Neil Simpson Unit 2	Neil Simpson Unit 2	Wygen 3	Wygen 3	Wyodak
36	Fuel Kind	Oil	Natural Gas	Oil	Natural Gas	Natural Gas	Natural Gas	Coal	Natural Gas	Coal	Natural Gas	Coal
37	Fuel Unit	Bbl	McF	Bbl	McF	McF	McF	Tons	McF	Tons	McF	Tons
38	Quantity (Units) of Fuel Burned	64	63,924	69	1,850,134	415,076	732,893	488,638	18,336	297,436	6,384	273,671
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	134,775	1,068	133,811	1,050	1,068	1,068	7,914	1,071	7,981	1,073	7,895
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year		4.45	389.32	5.19	3.92	4.66	16.83	4.73	16.65	8.39	21.56
41	Average Cost of Fuel per Unit Burned		4.45	389.32	5.19	3.92	4.66	20.24	4.73	21.15	8.39	25.61
42	Average Cost of Fuel Burned per Million BTU	15.46	4.17	724.00	4.95	2.99	4.36	1.27	4.41	1.33	7.82	1.62
43	Average Cost of Fuel Burned per kWh Net Gen		0.077		0.037	0.043	0.047	0.003		0.003	0.103	0.014

44	Average BTU per kWh Net Generation		[(d)]9,865		7,543	11,614	10,709	[(e)]12,624		[(f)]12,021		[(g)]8,741

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: PlantName

The amounts shown below reflect our 58% ownership interest in the 100 MW Cheyenne Prairie Generating Station combined cycle unit. Our affiliate, Cheyenne Light, Fuel and Power owns the remaining 42% of this facility.

(b) Concept: PlantName

The amounts shown below reflect our 52% ownership interest in the 116 MW Wygen III coal-fired power plant at the Gilletee, Wyoming energy complex. MDU owns 25% and the City of Gillette owns the remaining 23% of the Wygen III power plant.

(c) Concept: PlantName

The amounts shown below reflect our 20% ownership interest in the Wyodak Plant, a mine-mouth coal-fired electric generating station located at the Gillette, Wyoming energy complex. PacifiCorp owns the remaining ownership percentage and operates the Wyodak Plant.

(d) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration

Composite of both coal and natural gas

(e) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration

Composite of both coal and natural gas

(f) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration

Composite of both coal and natural gas

(g) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration

Composite of both coal and natural gas

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. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:
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					

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

Pumped Storage Generating Plant Statistics

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

Line No.	Item (a)	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:
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				
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))				

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
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	[(a)] Corriedale Wind Farm	2020	32.5	32.5	126,390,720	49,068,674	3.88	568,918		2,894	Wind		Wind

FOOTNOTE DATA

(a) Concept: PlantName
The amounts presented reflect our 62% ownership interest (32.5 MW) in the 52.5 MW Corriedale wind farm. Our affiliate, Cheyenne Light, Fuel and Power owns the remaining 38% interest (20 MW) in this facility.

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

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/provided to a generator's own load requirements or used for the provision of ancillary services.
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 affiliated seller specify how the cost of the power was determined. In columns (n) and (o), report 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, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	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)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Account for Project Costs (p)	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
1																			
35	TOTAL																		

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a), (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)	BALANCE AT BEGINNING OF YEAR				
					Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
1									
36	TOTAL								

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
5. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
6. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
8. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	Osage	Lange	230.00	230.00	H-Wood	19.27		1	1272 KCM ACSR	589,324	10,387,094	10,976,418				
2	[a] Fall River	Stegall	230.00	230.00	H-Wood	94.47		1	1272 KCM ACSR	329,367	23,299,206	23,628,573				
3	Wyodak	Lookout	230.00	230.00	H-Wood	11.03		1	1272 KCM ACSR	9,800	5,812,623	5,822,423				
4	Lookout	Lange	230.00	230.00	H-Wood	54.53		1	1272 KCM ACSR	105,653	16,904,151	17,009,804				
5	Lange	West Hill	230.00	230.00	H-Wood	2.70		1	1272 KCM ACSR		3,563,100	3,563,100				
6	West Rapid Tap	West Rapid	230.00	230.00	SP-Steel	0.70		2	1272 KCM ACSR							
7	West Rapid Tap	South Rapid	230.00	230.00	H-Wood	5.30		1	1272 KCM ACSR	947,829	7,665,177	8,613,006				
8	South Rapid	West Hill	230.00	230.00	H-Wood	47.50		1	1272 KCM ACSR		11,863,841	11,863,841				
9	West Hill	Fall River	230.00	230.00	H-Wood	22.75		1	1272 KCM ACSR	17,701	8,972,019	8,989,720				
10	[b] Fall River	Stegall	230.00	230.00	H-Wood	11.33		1	1272 KCM ACSR		365,576	365,576				
11	West Hill	Minnekahta	230.00	230.00	H-Wood	9.48		1	1272 KCM ACSR		863,095	863,095				
12	Minnekahta	Osage	230.00	230.00	H-Wood	23.32		1	1272 KCM ACSR	151,235	2,264,505	2,415,740				
13	Lange	Ben French	69.00	69.00	H-Wood	3.04		[a] 2	795 KCM ACSR	44,944	4,521,620	4,566,564				
14	[c] DC Tie West	South Rapid City	230.00	230.00	SP-Steel	4.00		1	1272 KCM ACSR	127,144	630,238	757,382				
15	[d] Osage	Yellowcreek	230.00	230.00	H-Wood	21.12		1	1272 KCM ACSR	1,533	273,459	274,992				
16	Osage	Lange	230.00	230.00	H-Wood	46.02		1	1272 KCM ACSR	1,512,324	24,504,272	26,016,596				
17	Wyodak	Lookout	230.00	230.00	H-Wood	73.26		1	1272 KCM ACSR	189,435	28,396,734	28,586,169				
18	Osage	Minnekahta	230.00	230.00	H-Wood	33.94		1	1272 KCM ACSR	96,159	2,785,313	2,881,472				
19	Osage	Wyodak	230.00	230.00	H-Wood	57.46		1	1272 KCM ACSR	162,516	4,779,483	4,941,999				
20	Neil Simpson I	Neil Simpson II	69.00	69.00	SP-Steel	0.80		1	795 KCM ACSR		304,794	304,794				
21	[e] Osage	Yellowcreek	230.00	230.00	H-Wood	22.02		1	1272 KCM ACSR	13,308	292,380	305,688				
22	Neil Simpson I	Wyodak	69.00	69.00	H-Wood	0.29		1	795 KCM ACSR		180,433	180,433				
23	Donkey Creek	Pumpkin Buttes	230.00	230.00	H-Wood	49.75		1	1272 KCM ACSR	1,280,649	10,038,199	11,318,848				
24	Wygen 3	Donkey Creek	230.00	230.00	SP-Steel	0.76		1	1272 KCM ACSR	3,488	296,454	299,942				
25	Pumpkin Buttes	Windstar	230.00	230.00	H-Steel	68.20		1	1272 KCM ACSR	2,204,209	13,657,908	15,862,117				
26	[f] Windstar	Dave Johnston	230.00	230.00	H-Steel	2.56		1	1272 KCM ACSR		686,732	686,732				
27	Donkey Creek	Wyodak Tie Line #2	230.00	230.00	Steel	1.06		2	1272 KCM ACSR		989,158	989,158				
28	WY 1.14 Tap	Wyodak Baghouse	230.00	230.00	H-Wood	0.10		1	336.4 ACSR		4,359	4,359				
29	Teckla	Osage	230.00	230.00	H-Wood	81.55		1	1272 KCM ACSR	2,467,545	24,700,805	27,168,350				
36	TOTAL					768.31		32		10,254,163	209,002,728	219,256,891				

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: TransmissionLineStartPoint
Fall River Substation was added in 2023, and split West Hill to Stegall
(b) Concept: TransmissionLineStartPoint
Fall River Substation was added in 2023, and split West Hill to Stegall
(c) Concept: TransmissionLineStartPoint
Owned 35% by Black Hills Power and 65% by Basin Electric
(d) Concept: TransmissionLineStartPoint
Owned 7.87% by Black Hills Power and 92.13% by Basin Electric
(e) Concept: TransmissionLineStartPoint
Owned 7.87% by Black Hills Power and 92.13% by Basin Electric
(f) Concept: TransmissionLineStartPoint
Owned 56.25% by Black Hills Power and 42.75% by Pacificorp
(g) Concept: NumberOfTransmissionCircuits
Rebuilt in 2022 as a double-circuit.

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1																	
44	TOTAL																

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
1	Anamosa, Rapid City, SD	Distribution	Unattended	69	12.47		20	1		Fans LTC		20
2	Argyle, SD	Distribution	Unattended	69	12.47		5	1		Fans		5
3	Belle Creek, MT	Distribution	Unattended	69	24.90		14	1		Fans		14
4	Ben French 26 Rapid City, SD	Distribution	Unattended	69	24.90		28	1		Fans. Regs		28
5	Butte Pipeline, Alzada, MT	Distribution	Unattended	69	2.40		13	3				13
6	Cambell St, Rapid City, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC		14
7	Cemetery, Rapid City, SD	Distribution	Unattended	69	12.47		28	2		Fans LTC		28
8	Century, Rapid City, SD	Distribution	Unattended	69	12.47		28	2		Fans LTC		28
9	Cleveland St. Rapid City, SD	Distribution	Unattended	69	12.47		25	1		Fans LTC		25
10	Cross Street, Rapid City, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC		14
11	Colony Substation, Colony, WY	Distribution	Unattended	69	24.90		14	1		Fans		14
12	Custer, SD	Distribution	Unattended	69	12.47		11	1		Fans LTC		11
13	Custer, SD	Distribution	Unattended	69	24.90		11	1		Fans. Regs		11
14	East Meade, Rapid City, SD	Distribution	Unattended	69	12.47		20	1		Fans LTC		20
15	East North, Rapid City, SD	Distribution	Unattended	69	12.47		34	2		Fans LTC		34
16	Edgemont City, Edgemont, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC		14
17	Fifth Street, Rapid City, SD	Distribution	Unattended	69	12.47		25	1		Fans LTC		25
18	Forty Fourth Street, Rapid City, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC		14
19	Fourth Street, Rapid City, SD	Distribution	Unattended	69	4.16		21	2		Fans LTC		21
20	Hill City, SD	Distribution	Unattended	69	24.90		14	1		Fans		14
21	Hillsview, Spearfish, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC		14
22	Hot Springs, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC		14
23	Lange, Rapid City, SD	Distribution	Unattended	69	24.90		14	1		Fans		14
24	Mall, Rapid City, SD	Distribution	Unattended	69	24.90		14	1		Fans Regs		14
25	Merillat, Rapid City, SD	Distribution	Unattended	69	12.47		28	2		Fans LTC		28
26	Mountain View, Spearfish, SD	Distribution	Unattended	69	24.90		14	1		Fans Regs		14
27	Newcastle, WY	Distribution	Unattended	69	4.16		11	1		Fans Regs		11
28	Newell, SD	Distribution	Unattended	25	4.16		2	1		Fans Regs		2
29	Newell, SD	Distribution	Unattended	25	12.47		1	3		Fans		1
30	Neil Simpson ST 4160 East, Gillette, WY	Distribution	Unattended	69	4.16		14	1		Fans		14
31	Neil Simpson 4160 West, Gillette, WY	Distribution	Unattended	69	4.16		11	1		Fans		11
32	Osage, WY Osage City Sub Osage, WY	Distribution	Unattended	69	12.47		11	1		Fans		11
33	Pleasant Valley, Rapid City, SD	Distribution	Unattended	69	12.47		20	1		Fans LTC		20
34	Pluma, Deadwood, SD	Distribution	Unattended	69	12.47		21	2		Fans LTC		21
35	Rapid City South, Rapid City, SD	Distribution	Unattended	69	12.47		34	2		Fans LTC		34
36	Radio Drive Rapid City, SD	Distribution	Unattended	69	12.47		34	2		Fans LTC		34
37	Richmond Hill, Lead, SD	Distribution	Unattended	69	12.47		5	1				5
38	Spearfish City, Spearfish, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC		14
39	Spearfish Park, Spearfish, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC		14
40	Spruce Gulch, Deadwood, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC		14
41	Sturgis, SD	Distribution	Unattended	69	12.47		28	2		Fans LTC		28
42	Sundance Hill, Belle Fourche, SD	Distribution	Unattended	69	24.90		11	1		Fans Regs		11
43	Sundance Hill, Belle Fourche, SD	Distribution	Unattended	69	4.16		7	1		Fans LTC		7
44	Thirty Eight St., Rapid City, SD	Distribution	Unattended	69	12.47		14	1		Fans LTC		14
45	Trojan, Lead, SD	Distribution	Unattended	69	12.47		11	1		Fans LTC		11
46	Upton, WY Upton city Sub Upton, WY	Distribution	Unattended	69	2.40		3	1		Fans Regs		3
47	West Boulevard, Rapid City, SD	Distribution	Unattended	69	4.16		11	1		Fans LTC		11
48	West Hill, Hot Springs, SD	Distribution	Unattended	69	12.47		11	1		Fans Regs		11
49	Whitewood, SD	Distribution	Unattended	69	24.90		14	1		Fans Regs		14
50	Windy Flats, Nemo	Distribution	Unattended	69	12.47		7	1		Fans		7

51	Portable Sub #1, Rapid City, SD	Distribution	Unattended	69	24.90		10	1		Fans		10
52	Portable Sub #2, Rapid City, SD	Distribution	Unattended	69	24.90		20	1		Fans		20
53	Pactola, Rapid City, SD	Distribution	Unattended	69	24.90		9	1		Fans		9
54	Piedmont, Piedmont, SD	Distribution	Unattended	69	24.90		14	1		Fans, Regs		14
55	Ben French Diesels, Rapid City, SD	Transmission	Unattended	4	69.00		14	1		Fans		14
56	Ben French Combustion Turbines, Rapid City, SD	Transmission	Unattended	14	69.00		120	4		Fans & Pumps		120
57	Cambell ST./East Tie, Rapid City, SD	Transmission	Unattended	115	69.00		80	2		Fans & Pumps		80
58	Lange, Rapid City, SD	Transmission	Unattended	230	69.00	13.2	250	2		Fans & Pumps		250
59	Lange CT, Rapid City, SD	Transmission	Unattended	14	69.00		75	1		Fans		75
60	Lookout, Spearfish, SD	Transmission	Unattended	230	69.00	13.2	250	2		Fans Pumps LTC		250
61	Neil Simpson 2 Gillette, WY	Transmission	Unattended	14	69.00		150	1		Fans		150
62	Neil Simpson CT #1, Gillette, WY	Transmission	Unattended	14	69.00		84	1		Fans		84
63	Osage 230, Osage WY	Transmission	Unattended	230	69.00	13.2	70	1		Fans, Pumps, LTC		70
64	West Hill Hot Springs, SD	Transmission	Unattended	230	69.00	13.2	50	1		Fans Pumps LTC		50
65	Wyodak 69 Sub, Gillette, WY	Transmission	Unattended	230	69.00	13.2	100	1		Fans Pumps LTC		100
66	Yellow Creek, Lead, SD	Transmission	Unattended	230	69.00	13.2	250	2		Fans Pumps LTC		250
67	Rapid City South, Rapid City, SD	Transmission	Unattended	230	69.00		150	1		Fans LTC		150
68	Rapid City AC_DC_AC Tie Rapid City SD	Transmission	Unattended	230	230.00		218	4	1	Fans LTC		218
69	Minnekahta Substation, Hot Springs, SD	Transmission	Unattended	230	69.00	13.2	70	1		Fans LTC		70
70	Blucksberg, Sturgis, SD	Distribution	Unattended	69	24.90		20	1		Fans LTC		20
71	Sagebrush, Newcastle, WY	Transmission	Unattended	230	69.00	13.2	100	1		Fans LTC		100
72	West Rapid City, Rapid City, SD	Transmission	Unattended	230	69.00	13.2	150	1		Fans LTC		150
73	Red Rock, Rapid City, SD	Distribution	Unattended	69	12.47		20	1		Fans LTC		20
74	Total						3,062					3,062

Name of Respondent: Black Hills Power Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ 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)] Allocation of direct and indirect costs provided by BHSC	Black Hills Service Company	[(c)] Various	58,526,103
3	[(b)] Allocation of Cheyenne Prairie Generating Station costs	Cheyenne Light, Fuel and Power	[(d)] Various	3,100,919
4	Rent expense from Gillette Energy Complex shared facilities agreement	Cheyenne Light, Fuel and Power	507.0	399,438
5	Rent expense from Gillette Energy Complex shared facilities agreement	Black Hills Wyoming	507.0	16,157
6	Costs under spare turbine agreements	Cheyenne Light, Fuel and Power	550.0	679,179
7	Costs under spare turbine agreements	Black Hills Colorado IPP	550.0	106,725
8	Ground lease with WRDC	Wyodak Resources Development Corp.	507.0	1,162,755
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Revenue from affiliates under spare turbine agreements	Cheyenne Light, Fuel and Power	454.0	1,746,590
22				
23	[(e)] Allocation of Gillette Energy Complex shared facilities costs	Cheyenne Light, Fuel and Power	[(h)] Various	2,385,081
24	[(f)] Allocation of Gillette Energy Complex shared facilities costs	Black Hills Wyoming	417.1	2,403,795
25	[(g)] Allocation of Corriedale Wind Farm costs	Cheyenne Light, Fuel and Power	[(i)] Various	402,874
26	Gillette Energy Complex rent revenue	Cheyenne Light, Fuel and Power	454.0	1,234,967
27	Gillette Energy Complex rent revenue	Black Hills Wyoming	454.0	1,476,381
28	Rent revenue from Horizon Point facility	Black Hills Service Company	454.0	11,086,908
42				

FOOTNOTE DATA

(a) Concept: DescriptionOfNonPowerGoodOrService

Black Hills Power (BHP) has a service agreement with Black Hills Service Company (BHSC), whereby BHSC charges BHP, at cost, for various direct and indirect services provided to BHP. Pursuant to the BHSC Cost Allocation Manual, indirect service cost allocations are determined in accordance with the Public Utility Holding Company Act of 2005.

Shown below is a summary of BHSC costs by service for the year ended December 31, 2023:

Customer Service	$2,489,402
Generation Support	37,828
Transmission	11,449,308
Generation Dispatch and Power Marketing	1,396,961
General Accounting	3,279,873
Executive Management	1,409,271
FERC Tariff and Compliance	1,066,163
Regulatory & Government Affairs	2,292,928
Environmental Services	946,277
Finance & Treasury	944,004
Information Technology	12,585,425
Safety	437,125
Power Delivery Management	1,308,766
Human Resources	1,466,031
Communications	570,490
Generation Plant Operations	552,275
Corporate Development	1,964,824
Credit & Risk	312,893
Organizational Development & Training	74,786
Internal Audit	438,602
Supply Chain Management	2,498,922
Legal	6,139,473
Tax	640,804
Marketing & External Affairs	282,472
Other Miscellaneous	3,941,200
	$58,526,103

(b) Concept: DescriptionOfNonPowerGoodOrService

Cheyenne Prairie Generating Station (Cheyenne Prairie), a 140 MW natural-gas fired power generation facility, includes one combined-cycle 100 MW unit that Black Hills Power jointly owns with Cheyenne Light Fuel and Power, an affiliate operating in the Cheyenne, Wyoming area. Black Hills Power owns 58 MW, and Cheyenne Light Fuel and Power owns 42 MW of this combined-cycle unit. Cheyenne Prairie also includes one simple-cycle 40 MW combustion turbine that Cheyenne Light Fuel and Power wholly owns. Black Hills Service Company (BHSC) is responsible for plant operations. Black Hills Power is committed to pay its proportionate share of the additions, replacements and operating and maintenance expenses.

(c) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Operating Revenues	$(36,702)
Operation Expenses	43,802,180
Maintenance Expenses	8,493,457
Depreciation Expense (403)	4,196,843
Amort. & Depl. of Utility Plant (404-405)	193,310
Taxes Other Than Income Taxes (408.1)	1,306,633
Taxes Other Than Income Taxes (408.2)	2,412
Revenues From Merchandising, Jobbing and Contract Work (415)	(16,398)
Costs and Exp. of Merchandising, Job. & Contract Work (416)	11,673
Expenses of Nonutility Operations (417.1)	87,195
Donations (426.1)	149,072
Exp. for Certain Civic, Political & Related Activities (426.4)	196,665
Miscellaneous Nonoperating Income (421)	(199,659)
Penalties (426.3)	524
Other Deductions (426.5)	338,896
	$58,526,103

(d) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Operation Expenses	$2,291,618
Maintenance Expenses	738,001
Taxes Other Than Income Taxes (408.1)	71,300
	$3,100,919

(e) Concept: DescriptionOfNonPowerGoodOrService

Black Hills Power has a shared facilities agreement with Cheyenne Light Fuel and Power and Black Hills Wyoming whereby certain assets owned by one or more of the entities at the Gillette Energy Complex in Gillette, Wyoming may be used to support the operations of one or more of the other entities. Under the agreement, each entity is charged a fee for the use of shared assets and is responsible for a share of operations and maintenance costs associated with the shared assets based on each entity's nameplate generation capacity. Black Hills Power has been appointed as Operator of the complex and is responsible for operating, maintaining and managing the shared assets, as well as administering the agreement.

(f) Concept: DescriptionOfNonPowerGoodOrService

Black Hills Power has a shared facilities agreement with Cheyenne Light Fuel and Power and Black Hills Wyoming whereby certain assets owned by one or more of the entities at the Gillette Energy Complex in Gillette, Wyoming may be used to support the operations of one or more of the other entities. Under the agreement, each entity is charged a fee for the use of shared assets and is responsible for a share of operations and maintenance costs associated with the shared assets based on each entity's nameplate generation capacity. Black Hills Power has been appointed as Operator of the complex and is responsible for operating, maintaining and managing the shared assets, as well as administering the agreement.

(g) Concept: DescriptionOfNonPowerGoodOrService

Corriedale, a 52.5 MW wind farm near Cheyenne, Wyoming, serves as the dedicated wind energy supply to the Renewable Ready program, which is a voluntary renewable energy subscription program for large commercial, industrial and governmental customers in South Dakota and Wyoming. Black Hills Power owns 32.5 MW (62%) and Cheyenne Light Fuel and Power (CLFP) owns 20 MW (38%) of this wind farm. Black Hills Power and CLFP are committed to pay their proportionate share of the additions, replacements and operating and maintenance expenses. BHSC is responsible for operations of the wind farm.

(h) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Operation Expenses	$1,285,310
Maintenance Expenses	1,040,413
Taxes Other Than Income Taxes (408.1)	59,256
Donations (426.1)	102
	$2,385,081

(i) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Operation Expenses	$400,199
Maintenance Expenses	1,895
Taxes Other Than Income Taxes (408.1)	780
	$402,874