

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: 2024/ Q4

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

## GENERAL INFORMATION

### I. Purpose

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

### II. Who Must Submit

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

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

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

### III. What and Where to Submit

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

The CPA Certification Statement should:

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

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

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

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

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

- Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at <https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online>.
- Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from <https://www.ferc.gov/general-information-0/electric-industry-forms>.

### IV. When to Submit

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

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

### 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

- Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USoFA). Interpret all accounting words and phrases in accordance with the USoFA.
- Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.
- Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly

### FERC FORM NO. 1 (ED. 03-07)

- and completely states the fact.
- For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.
- Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).
- Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.
- For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.
- Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.
- Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.
- Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

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

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

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

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

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

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

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

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

### DEFINITIONS

- Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.
- Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

## EXCERPTS FROM THE LAW

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

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

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

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

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

"Sec. 304.

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

## 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. § 825(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: 2024/ 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 Rd. 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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission
10 Date of Report (Mo, Da, Yr) 12/31/2024	

**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) 04/03/2025
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:  
12/31/2024

Year/Period of Report  
End of: 2024/ Q4

**LIST OF SCHEDULES (Electric Utility)**

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	Not applicable
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106	
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	Not applicable
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	Not applicable
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	Not applicable
22	Materials and Supplies	227	
23	Allowances	228	
24	Extraordinary Property Losses	230a	Not applicable
25	Unrecovered Plant and Regulatory Study Costs	230b	Not applicable
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	Not applicable
32	Capital Stock Expense	254b	
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	Not applicable
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	Not applicable
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	Not applicable
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
49	Transmission of Electricity by ISO/RTOs	331	Not applicable
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant (Account 403, 404, 405)	336	
53	Regulatory Commission Expenses	350	
54	Research, Development and Demonstration Activities	352	Not applicable
55	Distribution of Salaries and Wages	354	

56	Common Utility Plant and Expenses	386	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	
64	Hydroelectric Generating Plant Statistics	406	Not applicable
65	Pumped Storage Generating Plant Statistics	408	Not applicable
66	Generating Plant Statistics Pages	410	
66.1	Energy Storage Operations (Large Plants)	414	
66.2	Energy Storage Operations (Small Plants)	419	
67	Transmission Line Statistics Pages	422	
68	Transmission Lines Added During Year	424	
69	Substations	426	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
<b>Stockholders' Reports (check appropriate box)</b>			
Stockholders' Reports Check appropriate box:			
<input type="checkbox"/> Two copies will be submitted			
<input checked="" type="checkbox"/> No annual report to stockholders is prepared			

Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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**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.

Courtney Hebert  
Vice President - Corporate Controller  
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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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**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, 2024, Black Hills Corporation owned 100% of the common stock of Respondent.

**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)
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Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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**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	950,000		
2	Sr. Vice President and Chief Financial Officer	Kimberly F. Nooney	460,000		
3	Sr. Vice President and General Counsel	Phillip A. Casey	405,000	2024-11-13	
4	Sr. Vice President - Chief Human Resources Officer	Sarah A. Wiltse	350,000	2024-10-28	
5	Sr. Vice President - Utilities	Mame M. Jones	450,000		
6	Sr. Vice President - Chief Information Officer	Erik D. Keller	383,000		
7	Sr. Vice President - Growth and Strategy	Todd Jacobs	430,000		2024-08-05
8	Vice President - Black Hills Energy South Dakota and Wyoming	Wes Ashton	238,050		
9	Sr. Vice President and General Counsel	Brian G. Iverson	450,000		2024-09-06

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**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

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**INFORMATION ON FORMULA RATES**

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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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 System Formula Rate and BHP Formula Rate Protocols	ER18-1583-000, ER14-2689-000, ER08-1584-000
2	BHP JOATT, Schedule 2	ER15-2366-000, ER09-1292

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FOOTNOTE DATA

(a) Concept: RateScheduleTariffNumber

Because there is no annual filing for Schedule 2, page 106a is not completed. In addition, because Schedule 2 does not derive inputs from the FERC Form 1, page 106b is not completed.

FERC FORM No. 1 (NEW. 12-08)

Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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**INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding**

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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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	20240227-5227	02/27/2024	ER24-1356-000	Annual Informational Filing, Black Hills Power Attachment H, AC Transmission System Formula Rate and Formula Rate Protocols under ER24-1356	Attachment H

Name of Respondent:  
Black Hills Power Inc.

This report is:  
(1)  An Original  
(2)  A Resubmission

Date of Report:  
12/31/2024

Year/Period of Report  
End of: 2024/ Q4

**INFORMATION ON FORMULA RATES - Formula Rate Variances**

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

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
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Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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**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. None
7. None
8. None
9. The average annual union wage increase for Black Hills Power during 2024 was 5.20%. The average non-union wage increase for Black Hills Power during 2024 was 3.56%.
10. None
11. None
12. None
13. The following changes in officers occurred during the year: a. Brett Anderson's title changed from Vice President – Utility Services to Vice President – Customer and Supply Services effective February 5, 2024. Resigned effective October 11, 2024. b. Brian Weber's title changed from Vice President – Electric Transmission & Distribution Strategy and Engineering Services to Vice President – Utility Services and Transmission Strategy effective February 5, 2024. c. Nick Gardner was appointed Vice President – Engineering, Project Delivery and System Operations effective February 5, 2024. d. John A. Hill, Jr. was appointed Vice President – Safety, Compliance and Asset Programs effective February 5, 2024. Resigned effective July 31, 2024. e. Todd Jacobs, Senior Vice President – Growth and Strategy, resigned effective August 5, 2024. f. Franki Coulter, Vice President – Human Resources, was removed as an officer effective September 3, 2024. g. Brian G. Iverson, Director, Senior Vice President, General Counsel, Chief Compliance Officer and Assistant Corporate Secretary, retired effective September 6, 2024. h. Steven C. Dunn was appointed to Vice President – Pipeline Compliance and Asset Management effective October 14, 2024. i. Sarah A. Wiltse was appointed Senior Vice President – Chief Human Resources Officer effective October 28, 2024. j. Phillip A. Casey was appointed Senior Vice President – Chief Legal Officer and General Counsel effective November 13, 2024.
14. None

Name of Respondent:  
Black Hills Power Inc.

This report is:  
(1)  An Original  
(2)  A Resubmission

Date of Report:  
12/31/2024

Year/Period of Report  
End of: 2024/ 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	<b>UTILITY PLANT</b>			
2	Utility Plant (101-106, 114)	200	1,810,191,675	1,768,004,812
3	Construction Work in Progress (107)	200	52,908,341	19,809,320
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,863,100,016	1,787,814,132
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	551,839,174	518,023,276
6	Net Utility Plant (Enter Total of line 4 less 5)		1,311,260,842	1,269,790,856
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)		1,311,260,842	1,269,790,856
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	<b>OTHER PROPERTY AND INVESTMENTS</b>			
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)		1,158,472	828,691
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		2,788,134	3,053,090
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)		3,946,606	3,881,781
33	<b>CURRENT AND ACCRUED ASSETS</b>			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		33,146	
36	Special Deposits (132-134)			
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		18,312,575	17,006,222
41	Other Accounts Receivable (143)		2,502,050	1,997,150
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		108,493	139,482
43	Notes Receivable from Associated Companies (145)		12,018	13,623,211
44	Accounts Receivable from Assoc. Companies (146)		10,032,836	11,490,800
45	Fuel Stock (151)	227	7,095,782	7,162,936
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	34,033,429	32,979,902
49	Merchandise (155)	227		
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	3,454,259	3,561,730
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		4,487,867	4,086,489
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			

61	Accrued Utility Revenues (173)		12,183,417	12,197,305
62	Miscellaneous Current and Accrued Assets (174)			266,843
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)		92,038,886	104,233,106
68	<b>DEFERRED DEBITS</b>			
69	Unamortized Debt Expenses (181)		1,851,623	1,984,513
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	82,238,548	70,380,555
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)		618,641	1,689,858
76	Clearing Accounts (184)		1,571,121	978,773
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	5,515,791	5,830,961
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
82	Accumulated Deferred Income Taxes (190)	234	46,055,939	48,503,497
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		137,851,663	129,496,937
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,545,097,997	1,507,402,680

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	(4,571)	
3	Bad Debt Reserve	718,682	
4	Bonus Compensation	289,803	
5	Credit Carryovers	-	15,763,131
5	Deferred Compensation	91,246	
6	Defined Benefit Pension Plan	4,449,922	
7	Defined Benefit Pension Plan AOCI	66,534	
8	Depreciation	-	2,079,133
9	Employee Benefit Plans	-	1,656,940
10	Line Extension Deposits	1,522,250	
11	Net Operating Loss Carryforward	3,219,238	
12	Non-qualified Pension Plan	221,227	
13	Operating Leases	2,766,304	
14	Production Tax Credits	11,577,888	
15	Regulatory Liabilities	18,073,934	21,059,500
16	Retiree Healthcare Plan	1,003,838	
17	Other	4,012,600	4,386,775
18	TOTAL Electric (Enter Total of lines 2 thru 7)	48,008,895	44,945,478
19			
20			
21	Gas		
22			
23			
24			
25	Other		
26	TOTAL Gas (Enter of lines 10 thru 15)		
27	Other (Specify)		
28	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	48,008,895	44,945,478

Name of Respondent:  
Black Hills Power Inc.

This report is:  
(1)  An Original  
(2)  A Resubmission

Date of Report:  
12/31/2024

Year/Period of Report  
End of: 2024/ 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	<b>PROPRIETARY CAPITAL</b>			
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	541,942,205	526,043,810
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)	(652,595)	(761,474)
16	Total Proprietary Capital (lines 2 through 15)		604,280,935	588,273,661
17	<b>LONG-TERM DEBT</b>			
18	Bonds (221)	256	340,000,000	340,000,000
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256	196,450,000	
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)		61,410	65,550
24	Total Long-Term Debt (lines 18 through 23)		536,388,590	339,934,450
25	<b>OTHER NONCURRENT LIABILITIES</b>			
26	Obligations Under Capital Leases - Noncurrent (227)		12,854,745	12,826,427
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		2,103,976	331,970
29	Accumulated Provision for Pensions and Benefits (228.3)		9,242,324	9,275,803
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)		858,737	832,828
35	Total Other Noncurrent Liabilities (lines 26 through 34)		25,059,782	23,267,028
36	<b>CURRENT AND ACCRUED LIABILITIES</b>			
37	Notes Payable (231)			
38	Accounts Payable (232)		22,096,000	18,349,819
39	Notes Payable to Associated Companies (233)		4,742,176	190,651,875
40	Accounts Payable to Associated Companies (234)		41,604,688	37,649,001
41	Customer Deposits (235)		1,464,322	6,386,793
42	Taxes Accrued (236)	262	9,909,222	7,509,986
43	Interest Accrued (237)		4,704,700	4,702,201
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		993,793	909,873
48	Miscellaneous Current and Accrued Liabilities (242)		5,816,766	7,382,029
49	Obligations Under Capital Leases-Current (243)		357,621	346,448
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)		91,689,288	273,888,025
55	<b>DEFERRED CREDITS</b>			
56	Customer Advances for Construction (252)		7,692,422	5,931,396
57	Accumulated Deferred Investment Tax Credits (255)	266		
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	1,638,914	2,925,888

60	Other Regulatory Liabilities (254)	278	94,110,133	95,360,910
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		164,913,424	160,437,399
64	Accum. Deferred Income Taxes-Other (283)		19,324,509	17,383,923
65	Total Deferred Credits (lines 56 through 64)		287,679,402	282,039,516
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,545,097,997	1,507,402,680



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	<b>Classification of TOTAL</b>								
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								



41	TOTAL Other Income (Enter Total of lines 31 thru 40)		4,475,676	5,252,814															
42	Other Income Deductions																		
43	Loss on Disposition of Property (421.2)																		
44	Miscellaneous Amortization (425)																		
45	Donations (426.1)		231,441	264,481															
46	Life Insurance (426.2)																		
47	Penalties (426.3)		151	524															
48	Exp. for Certain Civic, Political & Related Activities (426.4)		282,665	195,396															
49	Other Deductions (426.5)		353,679	430,244															
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		867,936	890,645															
51	Taxes Applic. to Other Income and Deductions																		
52	Taxes Other Than Income Taxes (408.2)	262	29,852	27,036															
53	Income Taxes-Federal (409.2)	262	(37,445)	(11,435)															
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)		(7,593)	15,601															
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		3,615,333	4,346,568															
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 Required Debt (428.1)		128,780	184,959															
65	(Less) Amort. of Premium on Debt-Credit (429)																		
66	(Less) Amortization of Gain on Required Debt-Credit (429.1)																		
67	Interest on Debt to Assoc. Companies (430)		13,364,648	16,109,040															
68	Other Interest Expense (431)		806,153	(174,412)															
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		996,669	1,235,266															
70	Net Interest Charges (Total of lines 62 thru 69)		33,717,274	35,298,683															
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		58,398,395	54,758,609															
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)		58,398,395	54,758,609															

**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		526,043,810	488,385,201
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		(42,500,000)	(17,100,000)
15	TOTAL Debits to Retained Earnings (Acct. 439)		(42,500,000)	(17,100,000)
16	Balance Transferred from Income (Account 433 less Account 418.1)		58,398,395	54,758,609
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)		541,942,205	526,043,810
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)		541,942,205	526,043,810
	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)			

**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)	58,398,395	54,758,609
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	50,693,987	50,039,371
5	Amortization of (Specify) (footnote details)	650,730	1,197,155
5.1	Amortization of utility plant	528,400	1,074,780
5.2	Amortization of plant acquisition adjustments	96,421	97,406
5.3	Accretion of Asset Retirement Obligation	25,909	24,969
8	Deferred Income Taxes (Net)	3,312,965	717,212
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	(987,562)	22,706,105
11	Net (Increase) Decrease in Inventory	(878,902)	(9,034,287)
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	(5,055,490)	(25,425,619)
14	Net (Increase) Decrease in Other Regulatory Assets	(7,888,012)	4,464,110
15	Net Increase (Decrease) in Other Regulatory Liabilities		
16	(Less) Allowance for Other Funds Used During Construction	21	
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	1,589,220	6,084,563
18.1	Bad debt expense	448,010	388,632
18.2	Deferred financing cost amortization	330,142	386,323
18.3	Employee benefit plan expense	566,478	445,880
18.4	Gain on disposition of property	(358,340)	(1,638,707)
18.5	Change in regulatory assets and liabilities impacting income statement	607,925	1,993,219
18.6	Changes in other current and non-current assets	633,865	5,582,220
18.7	Changes in other current and non-current liabilities	(638,860)	(1,073,004)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	99,835,310	105,507,219
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(82,890,254)	(60,978,179)
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	996,669	1,235,266
31	Other (provide details in footnote):	2,486,478	1,593,415
31.1	Cost of removal net of salvage	450,613	352,291
31.2	Contributions in aid of construction	2,105,026	1,445,161
31.3	Other investments	(69,161)	(204,037)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(81,400,445)	(60,620,030)
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)		(81,400,445)	(58,495,027)
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):		24,098,281	56,950,000
67.1	Net Borrowings from Money Pool		17,598,281	0
67.2	Net Borrowings of Notes Payable to Parent		6,500,000	56,950,000
70	Cash Provided by Outside Sources (Total 61 thru 69)		24,098,281	56,950,000
72	Payments for Retirement of:			
73	Long-term Debt (b)			
74	Preferred Stock			
75	Common Stock			
76	Other (provide details in footnote):		(42,500,000)	(104,693,401)
76.1	Dividend to Parent		(42,500,000)	(17,100,000)
76.2	Net Payments to Money Pool			(87,593,401)
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)		(18,401,719)	(47,743,401)
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)		33,146	(731,209)
88	Cash and Cash Equivalents at Beginning of Period		0	731,209
90	Cash and Cash Equivalents at End of Period		33,146	0

Name of Respondent: Black Hills Power Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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**NOTES TO FINANCIAL STATEMENTS**

- 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.
- 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 material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
- 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.
- 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.
- Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
- 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.
- For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the most recent information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
- 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.
- 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.

**NOTES TO FINANCIAL STATEMENTS**

**(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.

**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, 2024 and 2023, 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. Typically, our customers are billed monthly with payment due within 20 days. Any fixed consideration contracts with an expected duration of one year or more are immaterial to our revenues. Variable consideration 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 lease revenue under ASC 842, Leases, derivative revenue under ASC 815, Derivatives and Hedging, and 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 true-up and recorded in Accrued Utility Revenues (Account 173) on the accompanying Balance Sheets.

**Contract Balances**

The nature of substantially all of our revenue contracts provides an unconditional right to consideration upon service delivery. Therefore, customer contract assets or liabilities do not exist. The unconditional right to consideration is represented by the balance in our Accounts receivable, which is further discussed below.

**See Note 4 for additional information.**

**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	
2024	\$	139	\$	448	\$	251	\$	(730)	\$	108
2023	\$	182	\$	388	\$	180	\$	(611)	\$	139

**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-Debt (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 2.3% in 2024 and 2.4% in 2023.

**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 is 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.

**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 classified in their entirety based on 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 renewable tax credits, including PTCs and ITCs, as a reduction to income taxes payable under the scope of ASC 740 Income Taxes. We include the discount from the sale of our tax credits as a component of income tax expense. The sale of tax credits is presented within Operating activities in the Statement of Cash Flows consistent with the presentation of cash taxes paid. For renewable tax credits subject to future transfer, a valuation allowance is recorded for the difference between the tax value of the credits and the expected sales price. Tax credits and any related valuation allowances are derecognized when control of the tax credits is transferred to other corporate taxpayers. See Notes 3 and 9 for further discussion of the transfer of renewable tax credits to other corporate taxpayers, including related indemnification requirements and valuation allowances, respectively.

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):

	2024		2023
<b>Regulatory assets</b>			
Deferred energy, fuel and transmission cost adjustments <sup>(a)</sup>	\$ 37,722	\$	29,840
Deferred taxes on AFUDC <sup>(a)</sup>	3,812		3,988
Employee benefit plans and related deferred taxes <sup>(b)</sup>	17,802		17,155
Deferred taxes on flow through accounting <sup>(a)</sup>	22,599		19,100
Other regulatory assets <sup>(a)</sup>	304		298
<b>Total Other Regulatory Assets (182.3)</b>	<b>\$ 82,239</b>	<b>\$</b>	<b>70,381</b>
<b>Regulatory liabilities</b>			
Employee benefit plans and related deferred taxes <sup>(b)</sup>	\$ 6,559	\$	6,009
Excess deferred income taxes <sup>(b)</sup>	86,181		88,416
Other regulatory liabilities <sup>(b)</sup>	1,370		936
<b>Total Other Regulatory Liabilities (254)</b>	<b>\$ 94,110</b>	<b>\$</b>	<b>95,361</b>

- (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 recorded 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 Common Use System (discussed further in Note 6) annual rate determination process is governed by the FERC formula rate protocols established in the filed FERC joint-access transmission tariff. Effective January 1, 2024, the annual revenue requirement was \$33 million based on \$183.3 million of rate base.

**(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.

**Indemnification**

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.

**Transfers of Renewable Tax Credits**

In June 2024, we entered into an agreement with a third party to sell our 2023 generated PTCs. In January 2025, we entered into a similar agreement with the same third party to sell our 2024 generated PTCs. In each of these agreements, we provided indemnifications associated with the proceeds for PTCs transferred to the third party in the event of an adverse interpretation of tax law, including whether the related tax credits meet the qualification requirements. Additionally, in our agreement for the sale of our 2024 generated PTCs, we provided indemnifications in the event of a change in tax law. We believe the likelihood of having to make any material cash payments under these indemnifications is remote. See Note 9 for additional information.

**(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.

Customer types:	Year ended December 31,			
	2024		2023	
Retail	\$	230,532	\$	214,440
Wholesale		14,200		13,929
Market-off-system sales		16,469		35,648
Transmission/Other		66,518		62,601
Revenue from contracts with customers		327,719		326,618
Other revenues		275		282
<b>Total Revenues</b>	<b>\$</b>	<b>327,994</b>	<b>\$</b>	<b>326,900</b>
<b>Timing of revenue recognition:</b>				
Services transferred over time	\$	327,719	\$	326,618
Revenue from contracts with customers	\$	327,719	\$	326,618

**(5) PROPERTY, PLANT AND EQUIPMENT**

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

FERC Accounts	2024	Lives (in years)				
		2024 Weighted Average Useful Life (in years)	2023	2023 Weighted Average Useful Life (in years)	Minimum	Maximum
Electric plant:						
Production	\$ 731,081	44	\$ 716,603	45	25	61
Transmission	299,745	51	299,156	51	42	60
Electric distribution	569,292	45	541,257	45	21	62
Plant acquisition adjustment <sup>(a)</sup>	4,870	N/A	4,870	32		
General	188,412	27	183,024	28	3	40
Operating lease assets						
Total plant-in-service	1,810,192	N/A	1,781,422	1,781,422		
Construction work-in-progress	52,908		19,809			
Total electric plant	1,863,100		1,781,231			
Less accumulated depreciation and amortization	(551,839)		(518,023)			
<b>Electric plant net of accumulated depreciation and amortization</b>	<b>\$ 1,311,261</b>		<b>\$ 1,263,208</b>			

(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 7 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 82 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, 2024 and 2023, we were allocated net costs of \$3.4 million and \$3.1 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, 2024 and 2023, we allocated net costs of \$0.4 million and \$0.4 million, respectively, to Wyoming Electric.

As of December 31, 2024, 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%	\$ 123,014	\$(3)	\$(76,838)	\$ 46,173
Transmission Tie	35%	\$ 24,538	\$ 306	\$(8,314)	\$ 16,530
Wygen III	52%	\$ 144,799	\$ 288	\$(33,000)	\$ 112,087
Cheyenne Prairie	58%	\$ 118,800	\$ 1,060	\$(25,925)	\$ 93,935
Corriedale Wind Farm	62%	\$ 52,828	\$ -	\$(8,719)	\$ 44,109

#### (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, 2024, 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. For 2025, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 26% to 34% return-seeking assets and 66% to 74% 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:

	2024	2023
<b>Return-seeking Assets</b>		
Equity	19%	14%
Real estate	5%	5%
Hedge funds	3%	3%
Fixed income	3%	2%
Total	30%	24%
<b>Liability-hedging Assets</b>		
Fixed income	68%	74%
Cash	2%	2%
Total	70%	76%
<b>Total assets</b>	<b>100%</b>	<b>100%</b>

##### 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):

	2024	2023
<b>Defined Contribution Plans</b>		
Company Retirement Contribution	\$ 965	\$ 1,086
Matching Contributions	\$ 1,441	\$ 1,357
<b>Defined Benefit Plans</b>		
Pension Plan	\$ 305	\$ -
Healthcare Plan	\$ 360	\$ 345
Supplemental Plans	\$ 318	\$ 321

We do not have any required 2025 contributions, however, we currently expect to contribute \$0.2 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, 2024				Total Investments Measured at Fair Value	NAV <sup>(a)</sup>	Total Fair Value
	Level 1	Level 2	Level 3				
Recurring Fair Value Measures							
Common Collective Trust - Cash and Cash Equivalents	\$ -	\$ 737	\$ -	\$ 737	\$ -	\$ -	\$ 737
Common Collective Trust - Equity	-	6,999	-	6,999	-	-	6,999
Common Collective Trust - Fixed Income	-	25,939	-	25,939	-	-	25,939
Common Collective Trust - Real Estate	-	-	-	-	-	2,022	2,022
Hedge Funds	-	-	-	-	-	1,029	1,029
Total investments measured at fair value	\$ -	\$ 33,675	\$ -	\$ 33,675	\$ 3,051	\$ -	\$ 36,726
<b>Pension Plan</b>							
Recurring Fair Value Measures							
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

(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):

As of December 31,	Pension Plan		Supplemental Plans		Healthcare Plan	
	2024	2023	2024	2023	2024	2023
Service cost	\$ 138	\$ 144	\$ 29	\$ -	\$ 114	\$ 113
Interest cost	2,143	2,228	93	105	147	156
Expected return on assets	(2,369)	(2,408)	-	-	-	-
Amortization of prior service cost (credits)	(16)	(16)	-	-	(26)	(173)
Amortization of loss (gain)	-	-	-	-	-	(37)
Recognized net actuarial loss (gain)	436	440	20	14	-	-

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):

	Pension Plan			Supplemental Plans			Healthcare Plan		
	2024	2023	2022	2024	2023	2022	2024	2023	2022
Accumulated benefit obligation at December 31,	\$ 41,746	\$ 45,307	\$ 45,307	\$ 1,838	\$ 2,073	\$ 2,073	\$ 2,783	\$ 2,783	\$ 3,221
<b>Change in benefit obligation:</b>									
Projected benefit obligation at beginning of year	\$ 45,638	\$ 45,802	\$ 45,802	\$ 2,073	\$ 2,237	\$ 2,237	\$ 3,221	\$ 3,221	\$ 3,305
Service cost	138	144	29	-	-	-	114	114	113
Interest cost	2,143	2,228	93	105	105	147	147	155	155
Actuarial (gain) loss	(1,603)	(5,378)	(54)	(318)	(321)	(431)	(431)	(428)	(345)
Benefits paid	(4,302)	(5,378)	(5,378)	(318)	(321)	(321)	(360)	(360)	(345)
Plan participants transfer to affiliate	11	-	-	15	(1)	-	(1)	(1)	(1)
Plan participants' contributions	-	-	-	-	-	-	93	122	122
Projected benefit obligation at end of year	\$ 42,025	\$ 46,638	\$ 46,638	\$ 1,838	\$ 2,073	\$ 2,073	\$ 2,783	\$ 2,783	\$ 3,221
<b>Change in fair value of plan assets:</b>									
Fair value of plan assets at beginning of year	40,906	41,839	-	-	-	-	-	-	-
Investment income (loss)	(193)	1,444	-	-	-	-	-	-	-
Benefits paid	(4,302)	(5,378)	(318)	(321)	(321)	(360)	(360)	(345)	(345)
Participant contributions	-	-	-	-	-	-	93	122	122
Employer contributions	305	-	-	318	321	321	267	223	223
Plan participants transfer to affiliate	10	-	-	-	-	-	-	-	-
Fair value of plan assets at end of year	\$ 36,726	\$ 40,906	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Funded status - defined	\$ 5,299	\$ 4,733	\$ -	\$ 1,838	\$ 2,073	\$ 2,073	\$ 2,783	\$ 2,783	\$ 3,221
<b>Amounts recognized on our Balance Sheets as of December 31:</b>									
Other Regulatory Assets (182.3)	\$ 17,280	\$ 16,740	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 422
Miscellaneous Current and Accrued Liabilities (242)	-	-	-	-	-	-	-	-	-
Accumulated Provision for Pensions and Benefits (228.3)	5,300	4,733	1,505	1,754	1,754	2,386	2,789	2,789	2,789
Other Regulatory Liabilities (254)	-	-	-	-	-	-	1,965	1,965	1,965
<b>Amounts recognized in AOCI, net of tax as of December 31:</b>									
Net (gain) loss	\$ -	\$ -	\$ 339	\$ 397	\$ 397	\$ -	\$ -	\$ -	\$ -
Total amounts included in AOCI, after-tax net yet recognized as components of net periodic expense	\$ -	\$ -	\$ 339	\$ 397	\$ 397	\$ -	\$ -	\$ -	\$ -

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**

	Pension Plan		Supplemental Plans		Healthcare Plan	
	2024	2023	2024	2023	2024	2023
Weighted-average assumptions used to determine benefit obligations:						
Discount rate	5.63%	4.99%	5.52%	4.91%	5.60%	4.97%
Rate of increase in compensation levels	3.04%	3.04%	NA	NA	NA	NA
Weighted-average assumptions used to determine net periodic benefit cost for plan year:						
Discount rate <sup>(a)</sup>	4.99%	5.17%	4.91%	5.11%	4.97%	5.14%
Expected long-term rate of return on assets <sup>(b)</sup>	6.00%	6.00%	NA	NA	3.50%	3.10%
Rate of increase in compensation levels	3.04%	3.06%	NA	NA	NA	NA

(a) The estimated discount rate for the Defined Benefit Pension Plan is 5.63% for the calculation of the 2025 net periodic pension costs.  
 (b) The expected rate of return on Defined Benefit Pension Plan plan assets is 6.50% for the calculation of the 2025 net periodic pension costs.

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

	2024	2023
<b>Trend Rate - Medical</b>		
Pre-65 for next year - All plans	7.50%	6.69%
Pre-65 Ultimate trend rate	4.50%	4.50%
Trend Year	2035	2034
Post-65 for next year - all plans	6.50%	5.81%
Post-65 Ultimate trend rate	4.50%	4.50%
Trend Year	2033	2034

**Estimated Future Benefit Payments**

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

	Pension Plan	Supplemental Plans	Healthcare Plan
2025	\$ 3,610	\$ 289	\$ 397
2026	\$ 3,578	\$ 250	\$ 363
2027	\$ 3,520	\$ 218	\$ 371
2028	\$ 3,536	\$ 211	\$ 347
2029	\$ 3,567	\$ 205	\$ 317
2030-2034	\$ 16,625	\$ 791	\$ 1,276

**(9) INCOME TAXES**

**Transfers of Production Tax Credits**

In August 2022, President Biden signed H.R. 5376 into law, commonly known as the Inflation Reduction Act of 2022, or IRA. The IRA contains a tax credit transferability provision that allows us to transfer (e.g. sell) PTCs produced after December 31, 2022, to third parties. In June 2024, under this transferability provision, we entered into an agreement with a third party to sell \$3.6 million of our 2023 generated PTCs. In January 2025, we entered into a similar agreement with a third party to sell \$3.6 million of our 2024 generated PTCs.

We expect to continue to explore the ability to efficiently monetize our tax credits through third party transferability agreements.

**Income Tax Expense**

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

	2024	2023
Current income tax expense (Accounts 409.1 and 409.2)	\$ -	\$ 4,297
Deferred income tax expense (benefit) (Accounts 410.1 and 411.1)	\$ 5,142	\$ 717
Total income tax expense	\$ 5,142	\$ 5,014

**Effective Tax Rates**

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

	2024	2023
Federal statutory rate	21.0%	21.0%
Amortization of excess deferred income taxes	(2.8)	(2.9)
Flow-through adjustments <sup>(a)</sup>	(3.5)	(2.6)
Tax credits	(6.2)	(6.5)
Uncertain tax benefits	0.2	-
Other	(0.6)	(0.6)
Effective tax rate	8.1%	8.4%

(a) 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):

	2024	2023
<b>Deferred tax assets:</b>		
Regulatory liabilities	\$ 22,170	\$ 22,604
Employee benefit plans	1,657	1,676
Accumulated depreciation and other plant-related differences	2,079	1,559
Credit carryovers	15,763	15,109
Federal NOL	-	3,219
Other	4,387	4,536
Total deferred tax assets (Account 190)	46,056	48,503
<b>Deferred tax liabilities:</b>		
Regulatory assets	(8,643)	(8,071)
Accelerated depreciation and other plant related differences	(161,817)	(157,120)
Employee benefit plans	(3,048)	(3,053)
Deferred energy costs	(7,770)	(6,489)
Other	(2,960)	(3,088)
Total deferred tax liabilities (Accounts 282 and 283)	(184,238)	(177,821)
Net deferred tax assets (liabilities)	\$ (138,182)	\$ (129,318)

**Net Operating Loss and Tax Credit Carryforwards**

At December 31, 2024, we have federal NOL and tax credit carryforwards that will expire at various dates as follows (in thousands):

	Amounts	Expiration Dates
Federal tax credit carryforward	\$ 15,763	2030-2044

**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):

	2024	2023
Unrecognized tax benefits at January 1	\$ 1,091	\$ 950
Additions for prior year tax positions	150	-
Additions for current year tax positions	153	153
Reductions for prior year tax positions	(12)	(12)
Unrecognized tax benefits at December 31	\$ 1,382	\$ 1,091

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is \$1.4 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, 2024 and 2023, 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, 2025.

**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.

On May 10, 2024, FERC issued an order approving our compliance filing under FERC Order No. 894 to amortize protected excess and deficient deferred income taxes through the Average Rate Assumption Method and to issue a one-time bill credit for net unprotected excess and deficient deferred income taxes.

**(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 five years to 25 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, 2024 and 2023 were not material to the financial statements.

	Balance Sheet Location	As of December 31, 2024		As of December 31, 2023	
<b>Assets:</b>					
Operating leases	Utility Plant (101-106,114)	\$	16,792	\$	16,512
Operating leases	(Less) Accum. Prov. For Depr. Amort. Depl. (108, 110, 111, 115)		(3,588)		(3,961)
<b>Total lease assets</b>		<b>\$</b>	<b>13,204</b>	<b>\$</b>	<b>13,151</b>
<b>Liabilities:</b>					
Operating leases	Obligations Under Capital Leases - Noncurrent (227)	\$	12,854	\$	12,826
Operating leases	Obligations Under Capital Leases - Current (243)		368		347
<b>Total lease liabilities</b>		<b>\$</b>	<b>13,212</b>	<b>\$</b>	<b>13,173</b>

As of December 31, 2024, scheduled maturities of operating lease liabilities for future years were as follows (in thousands):

	Total	
2025	\$	1,095
2026		896
2027		896
2028		896
2029		896
Thereafter		16,848
<b>Total lease payments</b>	<b>\$</b>	<b>21,527</b>
Less imputed interest		(8,315)
<b>Present value of lease liabilities</b>	<b>\$</b>	<b>13,212</b>

#### (11) RELATED-PARTY TRANSACTIONS

##### Dividends to Parent

For the year ended December 31, 2024, we paid net dividends of \$42.5 million to our Parent. For the year ended December 31, 2023, we paid dividends of \$17.1 million 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 4.91% at December 31, 2024.

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

	2024		2023	
Money pool notes receivable - Notes Receivable from Associated Companies (145)	\$	-	\$	13,581
Money pool interest receivable - Notes Receivable from Associated Companies (145)	\$	12	\$	42
Money pool notes payable - Notes Payable to Associated Companies (233)	\$	3,987	\$	-

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

	2024		2023	
Money pool interest income (Account 419)	\$	1,045	\$	2,408
Money pool interest expense (Account 430)	\$	620	\$	5,150

##### 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. In conjunction with renewal of these Notes in 2024, we extended the Notes' term beyond twelve months. As a result, we reclassified these Notes payable to Parent from current to noncurrent.

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

	2024		2023	
Notes payable to Parent - Notes Payable to Associated Companies (233)	\$	-	\$	189,950
Long-term Notes payable to Parent - Notes Payable to Associated Companies (223)		196,450		-
Interest payable on borrowings from associated companies (233)		755		702

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

	2024		2023	
Notes payable to Parent interest expense - Interest on Debt to Assoc. Companies (430)	\$	8,653	\$	6,441

##### Interest Expense Allocation from Parent

BHC provides daily liquidity and cash management on behalf of all its subsidiaries. For the years ended December 31, 2024 and 2023, we were allocated \$4.4 million and \$4.8 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, 2024, we received \$0.7 million of net proceeds from BHC due to our tax sharing agreement. During the year ended December 31, 2023, we received \$5.2 million from BHC due to our tax sharing agreement. As of December 31, 2024, we had a \$2.6 million income tax payable from BHC related to our tax sharing agreement. As of December 31, 2023, we did not have an income tax receivable or payable 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, 2024 and 2023, South Dakota Electric allocated net costs of \$4.6 million and \$4.8 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 and Pueblo Airport 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):

	2024		2023	
<b>Operating Revenues:</b>				
Excess energy sold to Wyoming Electric	\$	11	\$	41
Rent revenue from affiliates under Gillette energy complex shared facilities agreement		3,248		2,711
Rent revenue from BHSC under Horizon Point shared facilities agreement		11,435		11,087
Spare turbine agreements with Black Hills Colorado IPP and Wyoming Electric		2,926		1,747
<b>Operating Expenses:</b>				
Purchases from WRDC	\$	18,829	\$	18,993
Purchases of excess energy from Wyoming Electric		28		961
Purchase of renewable wind energy from Wyoming Electric - Happy Jack		1,475		1,528
Purchase of renewable wind energy from Wyoming Electric - Silver Sage		3,534		3,486
Gas transportation service agreement with Wyoming Gas		239		267
Rent expense to affiliates under Gillette energy complex shared facility agreement		396		416
Wygen III ground lease with WRDC		1,200		1,163
Spare turbine agreements with Black Hills Colorado IPP and Wyoming Electric		764		786
Direct services and fees from BHSC		10,977		12,949
Indirect services and fees from BHSC		45,011		45,578

#### (12) SUPPLEMENTAL CASH FLOW INFORMATION

	2024		2023	
Years ended December 31, (in thousands)				
Cash (paid) refunded during the period for:				
Interest (net of amounts capitalized)	\$	(32,609)	\$	(32,694)
Income taxes, net of transferred tax credits		797		5,200
Non-cash investing and financing activities:				
Accrued property, plant and equipment purchases at December 31	\$	9,723	\$	6,780

#### (13) LONG-TERM DEBT

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

	Due Date	Interest Rate at December 31, 2024	December 31, 2024	December 31, 2023
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
<b>Total Bonds (221)</b>			<b>\$ 340,000</b>	<b>\$ 340,000</b>
Unamortized Debt Expenses (181)			1,852	1,985
Unamortized Discount on Long-Term Debt (226)			61	96

##### 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):

2025	\$	-
2026	\$	-
2027	\$	-
2028	\$	-
2029	\$	-
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, 2024.

#### (14) SUBSEQUENT EVENTS

We have evaluated subsequent events through April 3, 2025, which is the date the financial statements were available to be issued. Except as described in Notes 3 and 9, there have been no events subsequent to December 31, 2024, which would require recognition in the financial statements or disclosures.



**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		(367,488)			(415,048)		(782,536)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income		11,393			50,823		62,216		
3	Preceding Quarter/Year to Date Changes in Fair Value		(41,154)			0		(41,154)		
4	Total (lines 2 and 3)		(29,761)			50,823		21,062	54,758,609	54,779,671
5	Balance of Account 219 at End of Preceding Quarter/Year		(397,249)			(364,225)		(761,474)		
6	Balance of Account 219 at Beginning of Current Year		(397,249)			(364,225)		(761,474)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income		14,530			50,822		65,352		
8	Current Quarter/Year to Date Changes in Fair Value		43,527					43,527		
9	Total (lines 7 and 8)		58,057			50,822		108,879	58,398,395	58,507,274
10	Balance of Account 219 at End of Current Quarter/Year		(339,192)			(313,403)		(652,595)		

**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)	1,745,093,852	1,707,770,184		37,323,668			
4	Property Under Capital Leases	16,792,412	16,792,412					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	37,231,482	37,231,482					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	1,799,117,746	1,761,794,078		37,323,668			
9	Leased to Others							
10	Held for Future Use	6,203,620	6,203,620					
11	Construction Work in Progress	52,908,341	52,908,341					
12	Acquisition Adjustments	4,870,309	4,870,309					
13	Total Utility Plant (8 thru 12)	1,863,100,016	1,825,776,348		37,323,668			
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	551,839,174	539,804,518		12,034,656			
15	Net Utility Plant (13 less 14)	1,311,260,842	1,285,971,830		25,289,012			
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	543,950,747	531,916,091		12,034,656			
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	3,588,609	3,588,609					
22	Total in Service (18 thru 21)	547,539,356	535,504,700		12,034,656			
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	4,299,818	4,299,818					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	551,839,174	539,804,518		12,034,656			

Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases Amount includes operating leases in accordance with ASC Topic 842 and FERC Docket No. A119-1-000.
(b) Concept: UtilityPlantInServiceClassified Amounts in column (e) represent allocated property and related accumulated provision for depreciation from Black Hills Service Company.

**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	<b>SUBTOTAL (Total 2 thru 5)</b>					
7	<b>Nuclear Fuel Materials and Assemblies</b>					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	<b>SUBTOTAL (Total 8 &amp; 9)</b>					
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	<b>TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)</b>					
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	<b>Nuclear Materials held for Sale (157)</b>					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	<b>TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)</b>					

**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	55,880,783	490,202	125,914		81,443	56,326,514
10	(312) Boiler Plant Equipment	257,867,050	7,299,883	4,537,898		998,588	261,627,623
11	(313) Engines and Engine-Driven Generators	598,824					598,824
12	(314) Turbogenerator Units	124,545,009	725,307	654,519			124,615,797
13	(315) Accessory Electric Equipment	20,296,368	429,914	85,000			20,641,282
14	(316) Misc. Power Plant Equipment	3,416,100	68,269				3,484,369
15	(317) Asset Retirement Costs for Steam Production						
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	462,834,930	9,013,575	5,403,331		1,080,031	467,525,205
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	1,879,679	4,046,432		(4,046,432)		1,879,679
38	(341) Structures and Improvements	11,639,980	92,621	19,812			11,712,789
39	(342) Fuel Holders, Products, and Accessories	6,489,599	83,472	89,335		47,720	6,531,456
40	(343) Prime Movers						
41	(344) Generators	214,572,007	1,290,237	196,540		(722,029)	214,943,675
42	(345) Accessory Electric Equipment	22,284,587	(69,775)	411,816		411,816	22,214,812
43	(346) Misc. Power Plant Equipment	299,345	53,842				353,187
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)	257,921,241	5,496,829	717,503	(4,046,432)	(262,493)	258,391,642
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	720,756,171	14,510,404	6,120,834	(4,046,432)	817,538	725,916,847
47	3. Transmission Plant						
48	(350) Land and Land Rights	10,890,034	(552,959)				10,337,075
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	2,034,720	(11,151)	31,523		29,005	2,021,051

50	(353) Station Equipment	76,290,279	102,451	178,797		108,204	76,322,137
51	(354) Towers and Fixtures	864,826	151,222				1,016,048
52	(355) Poles and Fixtures	115,294,810	894,798	37,957		(41,341)	116,110,310
53	(356) Overhead Conductors and Devices	93,344,843	356,615	10,084	(93,516)	1,506	93,599,364
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)	298,726,432	940,976	258,361	(93,516)	97,374	299,412,905
59	4. Distribution Plant						
60	(360) Land and Land Rights	3,187,697	23,160				3,210,857
61	(361) Structures and Improvements	2,333,543	(2,335)	87			2,331,121
62	(362) Station Equipment	115,163,787	1,025,759	172,515		(108,303)	115,908,728
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	119,090,844	6,657,771	399,563	(183,564)	(428,836)	124,736,652
65	(365) Overhead Conductors and Devices	68,410,228	2,961,433	89,523		(81,609)	71,200,529
66	(366) Underground Conduit	24,748,209	471,470	56,605		(61,752)	25,101,322
67	(367) Underground Conductors and Devices	80,570,163	8,819,964	262,792	(74,220)	(122,902)	88,930,213
68	(368) Line Transformers	66,971,340	7,720,031	1,451,118	(86,216)	(1,202,343)	71,951,694
69	(369) Services	41,115,491	1,595,230	2,144		(35,191)	42,673,386
70	(370) Meters	11,809,625	676,095	204,986	278,026		12,558,760
71	(371) Installations on Customer Premises	3,227,987	122,743	382		(3,795)	3,346,553
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	2,913,032	991,181	321,667		(354,167)	3,228,379
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	539,541,946	31,062,502	2,961,382	(65,974)	(2,398,898)	565,178,194
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	5,167,253		12,232			5,155,021
87	(390) Structures and Improvements	85,762,782	860,820	150,376	79,262	30,581	86,583,069
88	(391) Office Furniture and Equipment	15,271,425	845,556	1,164,928			14,952,053
89	(392) Transportation Equipment	27,853,793	3,147,153	577,401			30,423,545
90	(393) Stores Equipment	166,937	53,795				220,732
91	(394) Tools, Shop and Garage Equipment	3,828,736	249,297	70,276			4,007,757
92	(395) Laboratory Equipment	770,778	(1,796)	26,482			742,500
93	(396) Power Operated Equipment	4,079,233	111,569	59,151			4,131,651
94	(397) Communication Equipment	6,831,887	159,719	256,104		17,837	6,753,339
95	(398) Miscellaneous Equipment	1,563,230	(37,115)	2,062			1,524,053
96	SUBTOTAL (Enter Total of lines 86 thru 95)	151,296,054	5,388,998	2,319,012	79,262	48,418	154,493,720
97	(399) Other Tangible Property	16,511,625	280,787				16,792,412
98	(399.1) Asset Retirement Costs for General Plant						
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	167,807,679	5,669,785	2,319,012	79,262	48,418	171,286,132
100	TOTAL (Accounts 101 and 106)	1,726,832,228	52,183,667	11,659,589	(4,126,660)	(1,435,568)	1,761,794,078
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)	1,726,832,228	52,183,667	11,659,589	(4,126,660)	(1,435,568)	1,761,794,078

Name of Respondent:  
Black Hills Power Inc.

This report is:  
(1)  An Original  
(2)  A Resubmission

Date of Report:  
12/31/2024

Year/Period of Report  
End of: 2024/ Q4

**ELECTRIC PLANT LEASED TO OTHERS (Account 104)**

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1						
2						
3						
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39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL					

**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	Kirk Station - Land	11/30/2022		2,810
4	Neil Simpson Station I - Land	10/01/2014		1,000
5	Osage Plant - Land	10/01/2014		149,038
6	St. Onge 230kV Substation - Land	07/01/2017		254,255
7	Catron Blvd. Rapid City Campus - Land	01/31/2023		887,365
8	Lange II - Land	05/01/2024		4,048,064
9				
21	Other Property:			
22	Osage Plant - Water/Well Assets	10/01/2014		815,962
47	TOTAL			6,203,620

Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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**CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)**

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	10080989-69/24.9kV MALL SUB. EXPANSION	4,475,924
2	60220997-Downtown Phase 5	1,853,645
3	DISTRIBUTION PLANT LESS THAN \$1,000,000 EACH	8,044,020
4	10078934-Field Area Network 2022 South Dakota Electric	2,943,305
5	GENERAL PLANT-ELECTRIC LESS THAN \$1,000,000 EACH	1,785,056
6	10084596-CT1 Major Overhead and Conversion	4,157,172
7	10088541-Large CT PD to PF Conversion	2,923,217
8	OTHER GENERATION -PLANT LESS THAN \$1,000,000 EACH	2,397,011
9	10085466-Large II	15,276,656
10	10078357-NSC Dual Fuel	3,864,962
11	10087925-WYGEN 1 Stator Rewind	1,356,479
12	10068176-NSC Training Simulator	1,335,614
13	STEAM GENERATION LESS THAN \$1,000,000 EACH	2,086,222
14	TRANSMISSION LESS THAN \$1,000,000 EACH	409,058
43	Total	52,908,341

**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)
<b>Section A. Balances and Changes During Year</b>					
1	Balance Beginning of Year	502,504,004	502,504,004		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	46,528,478	46,528,478		
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	991,546	991,546		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Right of Use	3,588,609	3,588,609		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	51,140,260	51,140,260		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(11,717,263)	(11,717,263)		
13	Cost of Removal	(1,512,606)	(1,512,606)		
14	Salvage (Credit)	251,221	251,221		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(12,978,648)	(12,978,648)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Asset Retirement Obligation and Pending Retirements	(5,160,916)	(5,160,916)		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	=535,504,700	535,504,700		
<b>Section B. Balances at End of Year According to Functional Classification</b>					
20	Steam Production	182,272,207	182,272,207		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	83,694,881	=83,694,881		
25	Transmission	50,271,467	50,271,467		
26	Distribution	181,963,880	181,963,880		
27	Regional Transmission and Market Operation				
28	General	37,302,265	37,302,265		
29	TOTAL (Enter Total of lines 20 thru 28)	=535,504,700	535,504,700		

(a) Concept: Accumulated Provision For Depreciation Of Electric Utility Plant

Note: Amounts footnoted are based upon FERC-approved rates

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	528,409,228	528,409,228		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	48,555,899	48,555,899		
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	2,774,758	2,774,758		
7	Other Clearing Accounts	-	-		
8	Other Accounts (Specify, details in footnote):	3,588,609	3,588,609		
9.1		-	-		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	54,950,893	54,950,893		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(11,717,263)	(11,717,263)		
13	Cost of Removal	(1,512,606)	(1,512,606)		
14	Salvage (Credit)	251,222	251,222		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(12,978,646)	(12,978,646)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Transfers	(5,160,916)	(5,160,916)		
18	Book Cost or Asset Retirement Costs Retired	-	-		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	565,220,559	565,220,559		
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	182,272,207	182,272,207		
21	Nuclear Production	-	-		
22	Hydraulic Production-Conventional	-	-		
23	Hydraulic Production-Pumped Storage	-	-		
24	Other Production	83,694,881	83,694,881		
25	Transmission	51,170,688	51,170,688		
26	Distribution	181,963,880	181,963,880		
27	Regional Transmission and Market Operation	-	-		
28	General	66,118,903	66,118,903		
29	TOTAL (Enter Total of lines 20 thru 28)	565,220,559	565,220,559		

(b) Concept: Accumulated Depreciation Other Production

Amount includes an Asset Retirement Obligation of \$128,777

(c) Concept: Accumulated Provision For Depreciation Of Electric Utility Plant

Note: Amounts footnoted are based upon FERC-approved rates

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	528,409,228	528,409,228		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	48,555,899	48,555,899		
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	2,774,758	2,774,758		
7	Other Clearing Accounts	-	-		
8	Other Accounts (Specify, details in footnote):	3,588,609	3,588,609		
9.1		-	-		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	54,950,893	54,950,893		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(11,717,263)	(11,717,263)		
13	Cost of Removal	(1,512,606)	(1,512,606)		
14	Salvage (Credit)	251,222	251,222		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(12,978,646)	(12,978,646)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Transfers	(5,160,916)	(5,160,916)		
18	Book Cost or Asset Retirement Costs Retired	-	-		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	565,220,559	565,220,559		
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	182,272,207	182,272,207		
21	Nuclear Production	-	-		
22	Hydraulic Production-Conventional	-	-		
23	Hydraulic Production-Pumped Storage	-	-		
24	Other Production	83,694,881	83,694,881		
25	Transmission	51,170,688	51,170,688		
26	Distribution	181,963,880	181,963,880		
27	Regional Transmission and Market Operation	-	-		
28	General	66,118,903	66,118,903		
29	TOTAL (Enter Total of lines 20 thru 28)	565,220,559	565,220,559		

Name of Respondent:  
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**INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)**

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1								
2								
3								
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36								
37								
38								
39								
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41								
42	Total Cost of Account 123.1 \$		Total					

**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)	7,162,936	7,095,782	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)	7,554,563	8,883,548	Transmission & Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	23,397,837	23,976,781	Production
8	Transmission Plant (Estimated)	258,612	151,544	Transmission
9	Distribution Plant (Estimated)	1,296,935	748,995	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	471,955	272,561	General
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	32,979,902	34,033,429	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	3,561,730	3,454,259	
17				
20	TOTAL Materials and Supplies	43,704,568	44,583,470	

Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

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

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**Allowances (Accounts 158.1 and 158.2)**

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(j), 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/transfersors 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	6,428		6,937		7,446		7,955		8,464		37,230	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	1,411		1,411		1,411		1,411		1,411		7,055	
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	(902)		(902)		(902)		(902)		(902)		(4,551)	
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	6,937		7,446		7,955		8,464		8,932		39,734	
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												

**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/transfers 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:  
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EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr.) (a)]	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
20	TOTAL					

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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						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent:  
Black Hills Power Inc.

This report is:  
(1)  An Original  
(2)  A Resubmission

Date of Report:  
12/31/2024

Year/Period of Report  
End of: 2024/ 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	<b>Transmission Studies</b>				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20	Total				
21	<b>Generation Studies</b>				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39	Total				
40	Grand Total				

**OTHER REGULATORY ASSETS (Account 182.3)**

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Energy Cost Adjustment	23,521,070	132,335,148	Various	124,942,839	30,913,379
2	Transmission Cost Adjustment	6,318,510	30,933,121	Various	30,463,607	6,788,024
3	Deferred Taxes on AFUDC	3,987,876	107,860	Various	283,449	3,812,287
4	Deferred Taxes on Flow Through Accounting	19,099,821	3,498,718			22,598,539
5	Deferred Taxes related to Retiree Healthcare Plan - Regulatory Liability	414,479	114,229	190.3	6,308	522,400
6	Pension Plan	16,740,184	975,706	Various	436,121	17,279,769
7	<sup>24</sup> Energy Efficiency	298,615				298,615
8	<sup>24</sup> Carbon Capture Compliance Surcharge		484,773	Various	479,450	5,323
9	Western Energy Imbalance Market (WEIM) Implementation Costs		35,443	Various	15,231	20,212
44	TOTAL	70,380,555	168,484,998		156,627,005	82,238,548

Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) 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.
(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Approved by Wyoming Public Service Commission in Docket No. 20002-127-ET-23.

**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	4,656,791	216,897	131	477,803	4,395,885
2	Corriedale Spare Parts Consigned Inventory	129,183		548	23,488	105,695
3	Wyoming Integrated Resource Plan		302,532	234	66,803	235,729
4	Carbon Capture	324,000		Various	404,529	(80,529)
5	Other Miscellaneous Deferred Debits	720,987	168,712	Various	30,688	859,011
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	<b>TOTAL</b>	<b>5,830,961</b>				<b>5,515,791</b>

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FOOTNOTE DATA

(a) Concept: MiscellaneousDeferredDebitsExcludingMiscellaneousWorkInProgress  
Prior year filing included Wyoming Integrated Resource Plan and Carbon Capture which have now been separated to individual lines items.

**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	(4,571)	
3	Bad Debt Reserve	718,682	
4	Bonus Compensation	289,803	
5	Credit Carryovers		=15,763,131
6	Deferred Compensation	91,246	
7	Defined Benefit Pension Plan	4,449,922	
8	Defined Benefit Pension Plan AOCI	66,534	
9	Depreciation		=2,079,133
10	Employee Benefit Plans		=1,656,940
11	Line Extension Deposits	1,522,250	
12	Net Operating Loss Carryforward	3,219,238	
13	Non-qualified Pension Plan	221,227	
14	Operating Leases	2,766,304	
15	Production Tax Credits	11,577,888	
16	Regulatory Assets	18,568,536	=22,169,960
17	Retiree Healthcare Plan	1,003,838	
7	Other	4,012,600	=4,386,775
8	TOTAL Electric (Enter Total of lines 2 thru 7)	48,503,497	46,055,939
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)	48,503,497	=46,055,939

Notes

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes  
 This amount was included in Production Tax Credits and Other in prior year filing.

(b) Concept: AccumulatedDeferredIncomeTaxes  
 This amount was included in Line Extension Deposits and Other in prior year filing.

(c) Concept: AccumulatedDeferredIncomeTaxes  
 This amount was included in Bonus Compensation, Deferred Compensation, Non-qualified Pension Plan, Retiree Healthcare Plan, and Other in prior year filing.

(d) Concept: AccumulatedDeferredIncomeTaxes  
 This amount was included in Defined Benefit Pension Plan, Regulatory Assets, and Other in prior year filing.

(e) Concept: AccumulatedDeferredIncomeTaxes  
 This amount was included in Abandonment Loss, Bad Debt Reserve, Net Operating Loss Carryforward, Operating Leases, Defined Benefit Pension Plan AOCI, and Other in prior year filing.

(f) Concept: AccumulatedDeferredIncomeTaxes

Note: Amounts footnoted are based upon FERC-approved rates

Line No.	Description and Location	Balance at Beginning of Year	Balance at End of Year
	(a)	(b)	(c)
1	Electric		
2	Abandonment Loss	(4,571)	
3	Bad Debt Reserve	718,682	
4	Bonus Compensation	289,803	
5	Credit Carryovers	-	15,763,131
5	Deferred Compensation	91,246	
6	Defined Benefit Pension Plan	4,449,922	
7	Defined Benefit Pension Plan AOCI	66,534	
8	Depreciation	-	2,079,133
9	Employee Benefit Plans	-	1,656,940
10	Line Extension Deposits	1,522,250	
11	Net Operating Loss Carryforward	3,219,238	
12	Non-qualified Pension Plan	221,227	
13	Operating Leases	2,766,304	
14	Production Tax Credits	11,577,888	
15	Regulatory Liabilities	18,073,934	21,059,500
16	Retiree Healthcare Plan	1,003,838	
17	Other	4,012,600	4,386,775
18	TOTAL Electric (Enter Total of lines 2 thru 7)	48,008,895	44,945,478
19			
20			
21	Gas		
22			
23			
24			
25	Other		
26	TOTAL Gas (Enter of lines 10 thru 15)		
27	Other (Specify)		
28	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	48,008,895	44,945,478

**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	50,000,000			23,416,396	23,416,396				
9	Preferred Stock (Account 204)									
11	Total									

**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	<b>Donations Received from Stockholders (Account 208)</b>	
2	Beginning Balance Amount	
3	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	<b>Reduction in Par or Stated Value of Capital Stock (Account 209)</b>	
6	Beginning Balance Amount	
7	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	<b>Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)</b>	
10	Beginning Balance Amount	
11	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	<b>Miscellaneous Paid-In Capital (Account 211)</b>	
14	Beginning Balance Amount	
15	Increases (Decreases) Due to Miscellaneous Paid-In Capital	
16	Ending Balance Amount	
17	<b>Other Paid in Capital</b>	
18	Beginning Balance Amount	
19	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	

Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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**CAPITAL STOCK EXPENSE (Account 214)**

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

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

**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 AE Bonds, 7.23%	Various	75,000,000		991,064			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		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			10/01/2014	10/20/2044	10/01/2014	09/30/2044	85,000,000	3,765,500
5	Subtotal		340,000,000		3,985,336		124,200					340,000,000	20,213,000
6	Reacquired Bonds (Account 222)												
7													
10	Subtotal												
11	Advances from Associated Companies (Account 223)												
12	Notes payable to Parent, 4.61%	Various	196,450,000					12/01/2024	12/31/2029			196,450,000	755,089
13	Subtotal		196,450,000									196,450,000	755,089
14	Other Long Term Debt (Account 224)												
15													
18	Subtotal												
33	TOTAL		536,450,000									536,450,000	20,968,089

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FOOTNOTE DATA

(a) Concept: InterestExpenseDebtAdvancesFromAssociatedCompanies

Interest expense in account 430 on the income statement also includes interest on both Utility Money pool notes payable and short-term Notes payable to Parent (account 233) as well as allocated interest expense from Parent related to daily liquidity and cash management services.

\$619,701 Utility Money Pool interest expense

\$7,897,734 Short-term Notes payable to Parent interest expense

\$755,089 Long-term Notes payable to Parent interest expense

\$4,092,124 BHC/Parent daily liquidity and cash management interest expense

\$13,364,648 Interest on Debt to Assoc. Companies (430)

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	58,398,395
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	5,142,589
11	Benefits Addback	151,711
12	Other Comprehensive Income	64,332
13	Operating Lease Asset	(53,200)
14	Straight Line Lease Asset	870
15	Required Bond Loss	128,780
16	Fines & Penalties	67,067
17	Asset Retirement Obligation FASB 143 Asset	57,536
18	Club Dues	64,516
19	Lobbying	29,675
20	Entertainment	4,775
21	Meals	120,988
22	Line Extension Deposit	138,688
23	Deferred Regulatory Asset	(7,321,251)
14	Income Recorded on Books Not Included in Return	
15	Operating Lease Liability	39,492
16	Public Utilities Commission Fees	40,363
17	Insurance Reserve	1,750,000
18	Prepaid Expense	(24,304)
19	Bad Debt Reserve	(23,106)
20	Benefits	1,583,209
21	Depreciation	(26,259,212)
22	Officer Supplemental Life Insurance	(148,077)
23	NOL Carryforward	(12,212,694)
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	21,741,142
28	Show Computation of Tax:	
29	Tax Amount	4,565,640
30	Tax Return True-up Adjustment	
31	Intercompany Payment	(2,736,016)
32	Total	1,829,624

**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 Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)	
1	Federal Unemployment Tax	Unemployment Tax	Federal	2024			9,663	9,650		13		19,674				(10,011)
2	Federal Insurance Contribution Tax	Federal Insurance Tax	Federal	2024	135,190		4,197,450	4,166,284		166,356		1,859,595				2,337,855
3	Federal Income Tax	Income Tax	Federal	2024			1,663,319	(952,915)		2,616,234		1,700,764				(37,445)
4	State Unemployment Tax	Unemployment Tax	SD	2024			2,705	2,703		2		15,724				(13,018)
5	State Income Tax	State Tax	MT	2024			166,305	166,305		0		166,305				
6	Property Tax	Property Tax	SD	2024	5,832,578		4,954,119	4,951,390		5,835,307		4,954,119				
7	Property Tax	Property Tax	WY	2024	1,161,989		2,834,924	3,054,165		942,748		2,834,924				
8	Property Tax	Property Tax	MT	2024	206,992		465,900	566,119		106,773		465,900				
9	Electric Generation Tax	Other State Tax	WY	2024			25,044	25,044		0		25,044				
10	Property Tax	Property Tax	NE	2024	144,785		152,774	165,106		132,453		152,774				
11	Accrued City Franchise Fee	Franchise Tax	WY	2024			56,894	56,894		0		56,894				
12	Accrued Sales/Use Tax	Sales And Use Tax	SD	2024	25,941		349,254	267,847		107,348		(840)				349,546
13	Accrued Sales/Use Tax	Sales And Use Tax	WY	2024	2,511		39,818	40,341		1,988		(7,820)				44,584
14	Regulatory Tax	Other State Tax	MT	2024			66,513	66,513		0		66,513				
40	<b>TOTAL</b>				7,509,986	0	14,984,682	12,585,446	0	9,909,222	0	12,309,570	0	0	0	2,671,511

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FOOTNOTE DATA

(a) Concept: TaxesIncurredOther

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

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Black Hills Power Inc.

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(1)  An Original  
(2)  A Resubmission

Date of Report:  
12/31/2024

Year/Period of Report  
End of: 2024/ 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									

**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	1,399,284	Various	1,458,517	104,626	45,393
2	Estimated Contract Liability	1,526,604	242	17,693	84,610	1,593,521
47	TOTAL	2,925,888		1,476,210	189,236	1,638,914

Name of Respondent:  
Black Hills Power Inc.

This report is:  
(1)  An Original  
(2)  A Resubmission

Date of Report:  
12/31/2024

Year/Period of Report  
End of: 2024/ 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)
			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)	Debits		Credits		
							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:  
12/31/2024

Year/Period of Report  
End of: 2024/ 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 relating 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				ADJUSTMENTS				Balance at End of Year (k)
			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)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	160,437,399	6,836,350	4,985,596			182.3	233,839	182.3	2,859,110	164,913,424
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	160,437,399	6,836,350	4,985,596				233,839		2,859,110	164,913,424
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	160,437,399	6,836,350	4,985,596				233,839		2,859,110	164,913,424
10	Classification of TOTAL										
11	Federal Income Tax	160,437,399	6,836,350	4,985,596			182.3	233,839	182.3	2,859,110	164,913,424
12	State Income Tax										
13	Local Income Tax										

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Note: Amounts footnoted are based upon FERC-approved rates

Line No.	Account	Balance at Beg of Year	Changes During Year				Adjustments				Balance at End 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	Debits		Credits		
							Account Credited	Amount	Account Debited	Amount	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	<b>Account 282</b>										
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	<b>Classification of TOTAL</b>										
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: AccumulatedDeferredIncomeTaxesOtherProperty

Note: Amounts footnoted are based upon FERC-approved rates

Line No.	Account	Balance at Beg of Year	Changes During Year				Adjustments				Balance at End 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	Debits		Credits		
							Account Credited	Amount	Account Debited	Amount	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	<b>Account 282</b>										
2	Electric	155,302,329	6,836,350	12,022,344		182.3	(2,859,110)	182.3	(233,839)	152,741,606	
3	Gas										
4	Other (Define)										
5	Total	155,302,329	6,836,350	12,022,344			(2,859,110)		(233,839)	152,741,606	
6											
7	TOTAL Account 282	155,302,329	6,836,350	12,022,344			(2,859,110)		(233,839)	152,741,606	
8	<b>Classification of TOTAL</b>										
9	Federal Income Tax	155,302,329	6,836,350	12,022,344		182.3	(2,859,110)	182.3	(233,839)	152,741,606	
10	State Income Tax										
11	Local Income Tax										

**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)
			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)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	☒ Deferred energy costs	6,489,245	1,805,153	524,508							7,769,890
4	☒ Employee benefit plans	3,053,237	432,704	438,240							3,047,701
5	☒ Other	2,965,979	78,483	97,328							13,510
6	☒ Regulatory liabilities	4,875,462		27,044		182.3, 219.0	62,160	182.3	760,016		5,546,274
9	TOTAL Electric (Total of lines 3 thru 8)	17,383,923	2,316,340	1,087,120			62,160		773,526		19,324,509
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)	☒17,383,923	2,316,340	1,087,120			62,160		773,526		☒19,324,509
20	Classification of TOTAL										
21	Federal Income Tax	17,383,923	2,316,340	1,087,120			62,160		773,526		19,324,509
22	State Income Tax										
23	Local Income Tax										

NOTES

(a) Concept: DescriptionOfAccumulatedDeferredIncomeTaxOther

Prior year category label was 'Deferred Costs' and has been updated for current year reporting

(b) Concept: DescriptionOfAccumulatedDeferredIncomeTaxOther

Prior year categories of 'Pension' and 'Prepaid Expenses' have been combined into 'Employee benefit plans' for current year reporting

(c) Concept: DescriptionOfAccumulatedDeferredIncomeTaxOther

Prior year categories of 'Goodwill', 'Operating Lease Asset', and 'Partnerships' have been combined into 'Other' category for current year reporting

(d) Concept: DescriptionOfAccumulatedDeferredIncomeTaxOther

Prior year categories of 'AFUDC', 'Reacquired Bond Loss', and Flow Through' have been combined into 'Regulatory liabilities' category for current year reporting

(e) Concept: AccumulatedDeferredIncomeTaxesOther

Note: Amounts footnoted are based upon FERC-approved rates

Line No.	Account	Balance at Beginning of Year	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End 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	Debits		Credits		
							Account Credited	Amount	Account Debited	Amount	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	<b>Account 283</b>										
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	<b>TOTAL Electric (Total of lines 3 thru 12)</b>	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	<b>Classification of TOTAL</b>										
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										

(f) Concept: AccumulatedDeferredIncomeTaxesOther

Note: Amounts footnoted are based upon FERC-approved rates

Line No.	Account	Balance at Beginning of Year	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End 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	Debits		Credits		
							Account Credited	Amount	Account Debited	Amount	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	<b>Account 283</b>										
2	Electric										
3	Employee Benefit Plans	3,053,237	432,705	438,240							3,047,701
4	Regulatory Liabilities	4,915,405	-	27,044				(760,017)	182.3	(212,302)	5,436,075
5	Deferred Energy Costs	6,489,245	1,805,153	524,508			182.3, 219				7,769,890
6	Other	2,965,979	78,483	97,328			182.3	(13,510)	182.3		2,960,644
7											
8	<b>TOTAL Electric (Total of lines 3 thru 12)</b>	17,423,866	2,316,340	1,087,120				(773,526)		(212,302)	19,214,310
9	Gas										
10											
11											
12											
13											
14	TOTAL Gas (Total of lines 15 thru 19)										
15	TOTAL Other										
16	TOTAL (Acct 283) (Enter Total of lines 12, 20, and 21)	17,423,866	2,316,340	1,087,120				(773,526)		(212,302)	19,214,310
17	<b>Classification of TOTAL</b>										
18	Federal Income Tax	17,423,866	2,316,340	1,087,120				(773,526)		(212,302)	19,214,310
19	State Income Tax										
20	Local Income Tax										

**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	936,101			434,448	1,370,549
2	Protected Property Excess Deferred Income Tax	78,349,656	Various	2,350,533	551,542	76,550,665
3	Non-Protected Property Excess Deferred Income Tax	10,066,000	Various	790,435	354,779	9,630,344
4	Deferred Taxes related to Pension Plan Regulatory Asset	4,449,923	190.3	102,348	245,781	4,593,356
5	Retiree Healthcare Plan	1,559,230	Various	25,886	431,875	1,965,219
41	<b>TOTAL</b>	95,360,910		3,269,202	2,018,425	94,110,133

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Prior year category of 'Excess Deferred Income Tax' has been broken apart for current year reporting

Note: Amounts footnoted are based upon FERC-approved rates

Line No.	Description and Purpose of Other Liabilities	Balance at Beginning of Current Quarter/Year	Debits		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
2	Protected Property Excess Deferred Income Taxes	75,885,424		5,140,738	551,542	71,296,229
3	Non-Protected Property Excess Deferred Income Taxes	10,174,984		932,887	354,779	9,596,875

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Prior year category of 'Excess Deferred Income Tax' has been broken apart for current year reporting

FERC FORM NO. 1 (REV 02-04)

**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	83,227,703	77,112,025	580,801	565,837	62,981	61,785
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	104,470,401	97,037,562	789,308	772,949	14,147	13,861
5	Large (or Ind.) (See Instr. 4)	38,812,842	36,927,877	467,005	469,450	24	24
6	(444) Public Street and Highway Lighting	1,209,259	1,207,305	9,921	10,015	219	217
7	(445) Other Sales to Public Authorities	2,364,883	2,156,471	22,970	21,701	152	149
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	230,085,088	214,441,240	1,870,005	1,839,952	77,523	76,036
11	(447) Sales for Resale	33,318,259	51,855,375	689,637	715,649	419	445
12	TOTAL Sales of Electricity	263,403,347	266,296,615	2,559,642	2,555,601	77,942	76,481
13	(Less) (449.1) Provision for Rate Refunds	8	416,728				
14	TOTAL Revenues Before Prov. for Refunds	263,403,339	265,879,887	2,559,642	2,555,601	77,942	76,481
15	Other Operating Revenues						
16	(450) Forfeited Discounts	274,897	281,631				
17	(451) Miscellaneous Service Revenues	447,326	415,098				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	21,858,902	21,371,088				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	1,070,059	1,004,842				
22	(456.1) Revenues from Transmission of Electricity of Others	42,019,022	39,668,357				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	65,670,206	62,741,016				
27	TOTAL Electric Operating Revenues	329,073,545	328,620,903				

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

Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue Commercial revenues
(b) Concept: LargeOrIndustrialSalesElectricOperatingRevenue Industrial revenues
(c) Concept: MiscellaneousServiceRevenues Consists of Site Visit and Interconnection Revenue
(d) Concept: OtherElectricRevenue Includes Planning Reserves and Wheeling Charges
(e) Concept: SmallOrCommercialSalesElectricOperatingRevenue Commercial revenues
(f) Concept: LargeOrIndustrialSalesElectricOperatingRevenue Industrial revenues
(g) Concept: MiscellaneousServiceRevenues Consists of site visit and interconnection revenue.
(h) 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:  
12/31/2024

Year/Period of Report  
End of: 2024/ 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					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

**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	MT910 - Regular Service	126	8,754	12	10,500	0.069
2	SD887 - Net Billing Total Electric Max	395	41,750	19	20,789	0.106
3	SDA24 - Private Area Lighting-A	741	115,007	216	3,431	0.155
4	SDB24 - Private Area Lighting-B	61	13,465	4	15,250	0.221
5	SDC24 - Private Area Lighting-C	1	93			0.093
6	WY798 - Rental		130			
7	WY910 - Regular Service	14,134	1,734,450	1,555	9,089	0.123
8	WY911 - BHP Residential	1	245	1	1,000	0.245
9	WY912 -Total Electric	4,021	473,824	354	11,359	0.118
10	WY913 - Total Electric	2	419	1	2,000	0.210
11	WY914 - Demand Service	175	22,229	11	15,909	0.127
12	SD710 - Regular Service	388,931	50,164,181	49,058	7,928	0.129
13	WY916 - Demand Service Max	1,452	173,218	84	17,286	0.119
14	WYA24 - Private Area Lighting-A	37	7,101	14	2,643	0.192
15	Energy Cost Adjustment		13,252,042			
16	Demand Side Management		4			
17	SD712 - Total Electric	90,951	9,492,680	7,538	12,066	0.104
18	SD714 - Demand Service	15,177	1,575,681	843	18,004	0.104
19	SD716 - Demand Service Max	62,873	5,929,734	3,068	20,493	0.094
20	SD717 - Utility Controlled	83	5,329	2	41,500	0.064
21	SD799 - Rental		1,911	7		
22	SD875 - Regular Service	792	110,508	96	8,250	0.140
23	SD876 - Net Billing Total Electric	698	85,996	98	7,122	0.123
41	TOTAL Billed Residential Sales	580,651	83,208,751	62,981	9,219	0.143
42	TOTAL Unbilled Rev. (See Instr. 6)	150	18,952			0.126
43	TOTAL	580,801	83,227,703	62,981	9,222	0.143

**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	MT920 - General Service	336	32,303	22	15,273	0.096
2	SD731 - Large General Service	38,935	3,027,528	6	6,489,167	0.078
3	SD750 - Small Interruptible General Service	59	5,596	1	59,000	0.095
4	SD755 - Energy Storage Service	10,640	783,841	31	343,226	0.074
5	SD770 - General Service-Special Events	1,645	273,835	136	12,096	0.166
6	SD771 - Large General Service	28,938	2,155,905	1	28,938,000	0.075
7	SD798 - Rental		2,582	2		
8	SD799 - Rental		22,977	63		
9	SD826 - Large General Service	11,362	1,159,886	31	366,516	0.102
10	SD827 - Large General Service	175,777	14,589,420	119	1,477,118	0.083
11	SD878 - Net Billing General Service	947	126,033	21	45,095	0.133
12	MT923 - General Service-Total Electric	8	726	2	4,000	0.091
13	SD879 - General Service	44	6,314	1	44,000	0.144
14	SD890 - Large General Service	430	56,143	1	430,000	0.131
15	SDA24 - Private Area Lighting-A	1,703	235,146	355	4,797	0.138
16	SDB24 - Private Area Lighting-B	632	124,834	65	9,723	0.198
17	SDC24 - Private Area Lighting-C	124	8,937	10	12,400	0.072
18	WY798 - Rental		981	4		
19	WY918 - General Service-No Demand	29	3,661	3	9,667	0.126
20	WY920 - General Service	37,541	4,299,557	530	70,832	0.115
21	WY921 - Large General Service-Secondary	2,171	228,717	3	723,667	0.105
22	WY923 - General Service-Total Electric	1,031	116,979	41	25,146	0.113
23	SD718 - General Service-No Demand	802	85,944	55	14,582	0.107
24	WYA24 - Private Area Lighting-A	65	12,588	14	4,643	0.194
25	WYB24 - Private Area Lighting-B	39	8,833	3	13,000	0.226
26	Energy Cost Adjustment		17,739,623			
27	Renewable Ready		1,603,421			
28	SD720 - General Service	361,128	46,044,957	11,651	30,995	0.128
29	SD721 - Large General Service-Secondary	77,920	7,700,818	89	875,506	0.099
30	SD722 - Large Demand Curtailable Service	495	37,940	1	495,000	0.077
31	SD723 - General Service-Total Electric	32,066	3,603,647	845	37,948	0.112
32	SD726 - Irrigation Pumping	952	129,122	29	32,828	0.136
33	SD727 - Utility Controlled General Service	2,370	160,300	12	197,500	0.068
41	TOTAL Billed Small or Commercial	788,189	104,389,094	14,147	55,714	0.132
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	1,119	81,307			0.073
43	TOTAL Small or Commercial	789,308	104,470,401	14,147	55,793	0.132

Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue
Commercial revenues

**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	MT920 - General Service Large	28	2,365	3	9,333	0.084
2	SDB24 - Private Area Lighting-B	2	490			0.245
3	WY798 - Rental		305			
4	WY921 - General Service Large	6,882	831,003	1	6,882,000	0.121
5	WY931 - Industrial Contract Services	63,808	4,335,760	1	63,808,000	0.068
6	WY934 - General Service Large	45,452	3,965,987	8	5,681,500	0.087
7	WYA24 - Private Area Lighting-A					
8	WYB24 - Private Area Lighting-B	11	2,570			0.234
9	Energy Cost Adjustment		6,393,839			
10	Renewable Ready		1,507,451			
11	MT930 - General Service Large	3,039	262,325	1	3,039,000	0.086
12	MT931 - General Service Large	16,279	1,296,911	2	8,139,500	0.080
13	MT932 - General Service Large	139,872	8,613,217	1	139,872,000	0.062
14	SD720 - General Service	236	83,433	4	59,000	0.354
15	SD761 - Industrial Contract Transmission	120,121	6,626,841	1	120,121,000	0.055
16	SD764 - Industrial Contract Services-Forest Products-Primary	20,790	1,597,885	1	20,790,000	0.077
17	SD774 - Industrial Contract Services-Forest Products-Primary	51,337	3,353,497	1	51,337,000	0.065
18	SDA24 - Private Area Lighting-A	2	316			0.158
41	TOTAL Billed Large (or Ind.) Sales	467,859	38,874,195	24	19,494,125	0.083
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(854)	(61,353)			0.072
43	TOTAL Large (or Ind.)	467,005	38,812,842	24	19,458,542	0.083

Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: LargeOrIndustrialSalesElectricOperatingRevenue
Industrial revenues

**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	SD741 - Customer Owned Service	6,020	428,110	30	200,667	0.071
2	SD742 - Traffic Signals	689	75,750	135	5,104	0.110
3	SD798 - Rental		240			
4	SD799 - Rental		16,279	6		
5	SD840 - Company Owned Service	2,773	602,329	34	81,559	0.217
6	SD841 - Customer Owned Service	116	11,854	5	23,200	0.102
7	SDA24 - Private Area Lighting	6	807	2	3,000	0.135
8	SDB24 - Private Area Lighting	1	269			
9	SDC24 - Private Area Lighting	8	671	2	4,000	
10	WY940 - Company Owned Service	251	66,972			0.267
11	WY941 - Customer Owned Service	49	4,209	1	49,000	0.086
12	WY942 - Traffic Signals	8	1,769	4	2,000	0.221
41	TOTAL Billed Public Street and Highway Lighting	9,921	1,209,259	219	45,301	0.122
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	9,921	1,209,259	219	45,301	0.122

**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.
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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	Energy Cost Adjustment		306,440			
2	Renewable Ready		20,324			
3	SD720 - Municipal Pumping	650	96,303	47	13,830	0.148
4	SD723 - Municipal Pumping	20	2,312	2	10,000	0.116
5	SD726 - Municipal Pumping	22	3,864	1	22,000	0.176
6	SD743 - Municipal Pumping	21,794	1,873,571	93	234,344	0.086
7	WY943 - Municipal Pumping	531	58,378	9	59,000	0.110
41	TOTAL Billed Other Sales to Public Authorities	23,017	2,361,192	152	151,428	0.103
42	TOTAL Unbilled Rev. (See Instr. 6)	(47)	3,691			
43	TOTAL	22,970	2,364,883	152	151,118	0.103

Name of Respondent:  
Black Hills Power Inc.

This report is:  
(1)  An Original  
(2)  A Resubmission

Date of Report:  
12/31/2024

Year/Period of Report  
End of: 2024/ 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)
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41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL			8		

**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)
41	TOTAL Billed - All Accounts	1,869,637	230,042,491	77,523	24,117	0.123
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	368	42,597			0.116
43	TOTAL - All Accounts	1,870,005	230,085,088	77,523	24,122	0.123

**SALES FOR RESALE (Account 447)**

- 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).
- Enter the name of the purchaser 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 purchaser.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

- 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).
- 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.
- 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.
- Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
- 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.
- 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.
- 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	60,751		1,357,208		1,357,208
2	Montana Dakota Utilities	RQ	3	47	47	47	164,669	2,686,750	4,968,978	697,186	8,352,914
3	Municipal Energy Agency of Nebraska (MEAN)	LU	3				111,214		7,060,527		7,060,527
4	Western Area Power Administration - Loveland Area Power	OS	3				52,251		2,394,841		2,394,841
5	Western Area Power Administration - Colorado River Storage Project	OS	3				75		10,525		10,525
6	Western Area Power Administration - Upper Great Plains	OS	3				1		19		19
7	Western Area Power Administration-WACM Marketing	OS	3				38,195		2,478,525		2,478,525
8	WACM-North West Power Pool	OS	3				956		59,635		59,635
9	Basin Electric Power	OS	3				6,371		221,425		221,425
10	Cheyenne Light Fuel and Power	OS	3				3,065		11,232		11,232
11	City of St George	OS	3				30		13,125		13,125
12	Colorado Springs Utilities	OS	3						(300)		(300)
13	Constellation Power/Exelon	OS	3				120		4,800		4,800
14	Coral Power	OS	3						(177)		(177)
15	Guzman Energy	OS	3				7,783		177,502		177,502
16	Macquarie Energy	OS	3				5,466		218,670		218,670
17	MAG Energy	OS	3				7		350		350
18	Mercuria	OS	3				480		35,200		35,200
19	Morgan Stanley	OS	3				1,525		39,150		39,150
20	Northwestern Energy	OS	3				155		8,300		8,300
21	PacifiCorp	OS	3				30,596		1,284,773		1,284,773
22	Phillips 66	OS					63,539		2,324,895		2,324,895
23	Portland General Electric	OS	3				330		12,540		12,540
24	Public Service Company of Colorado	OS	3				6,105		209,151		209,151
25	Public Service Company of New Mexico	OS	3				(651)		(24,476)		(24,476)
26	Southwest Power Pool-WEIS	OS	SPP RTO				4,761		165,996	2,648,952	2,814,948
27	The Energy Authority	OS	3				120		3,000		3,000
28	The Energy Authority (MEAN)	OS	3				12,578		466,598		466,598
29	TransAlta Energy	OS	3				209		52,250		52,250
30	Tri-State Generation	OS	3				7,604		196,830		196,830
31	United Power	OS	3				111,183		3,529,969		3,529,969
32	Utah Municipal Power Agency	OS	3				149		4,310		4,310
15	Subtotal - RQ						225,420	2,686,750	6,326,186	697,186	9,710,122
16	Subtotal-Non-RQ						464,217		20,959,185	2,648,952	23,608,137
17	Total						689,637	2,686,750	27,285,371	3,346,138	33,318,259

Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Affiliate transaction
(b) Concept: OtherChargesRevenueSalesForResale
Expense reimbursements
(c) Concept: OtherChargesRevenueSalesForResale
Other Charges - RTO Imbalance Market

**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	1,508,229	1,547,403
5	(501) Fuel	23,159,864	23,244,582
6	(502) Steam Expenses	1,522,637	1,508,409
7	(503) Steam from Other Sources		0
8	(Less) (504) Steam Transferred-Cr.		0
9	(505) Electric Expenses	621,093	608,529
10	(506) Miscellaneous Steam Power Expenses	1,463,942	1,495,317
11	(507) Rents	3,734,366	3,345,937
12	(509) Allowances		0
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	32,010,131	31,750,177
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	840,054	861,149
16	(511) Maintenance of Structures	827,704	679,641
17	(512) Maintenance of Boiler Plant	5,660,096	5,201,051
18	(513) Maintenance of Electric Plant	1,219,168	1,279,924
19	(514) Maintenance of Miscellaneous Steam Plant	81,085	33,201
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	8,628,107	8,054,966
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	40,638,238	39,805,143
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) Maintenance 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	1,164,352	1,061,948
63	(547) Fuel	12,640,453	14,920,362
64	(548) Generation Expenses	1,399,245	1,281,527
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	226,243	351,551
66	(550) Rents	2,409,945	2,358,216
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	17,840,238	19,973,604
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	739	11,543
70	(552) Maintenance of Structures	242	4,322
71	(553) Maintenance of Generating and Electric Plant	2,384,974	1,757,748
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	12,567	9,587
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	2,398,522	1,783,200
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	20,238,760	21,756,804
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	28,258,548	27,501,412
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	1,566,220	1,343,261
78	(557) Other Expenses	3,546	3,718
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	29,828,314	28,848,391
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	90,705,312	90,410,338
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	677,753	839,257
85	(561.1) Load Dispatch-Reliability	131,592	
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,097,784	855,648
87	(561.3) Load Dispatch-Transmission Service and Scheduling	85,779	180,935
88	(561.4) Scheduling, System Control and Dispatch Services	328,179	286,633
89	(561.5) Reliability, Planning and Standards Development	736,577	965,209
90	(561.6) Transmission Service Studies	15,012	
91	(561.7) Generation Interconnection Studies	64,577	496
92	(561.8) Reliability, Planning and Standards Development Services	129,633	267,640
93	(562) Station Expenses	359,692	395,974
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	38,715	66,330
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	27,662,909	27,115,755
97	(566) Miscellaneous Transmission Expenses	617,888	631,358
98	(567) Rents	68,331	(23,908)
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	32,014,421	31,581,327
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	65	
102	(569) Maintenance of Structures	19,597	18,259
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	151,257	86,852
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	120,363	102,452
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of Lines 101 thru 110)	291,282	207,583
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	32,305,703	31,788,890
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation	151,733	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)	151,733	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)	151,733	199,055
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,060,788	1,287,033
135	(581) Load Dispatching	620,169	613,394
136	(582) Station Expenses	690,830	669,177
137	(583) Overhead Line Expenses	365,832	262,270
138	(584) Underground Line Expenses	465,780	434,225
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	62,839	61,727
140	(586) Meter Expenses	564,446	510,591
141	(587) Customer Installations Expenses	572,870	373,200
142	(588) Miscellaneous Expenses	2,067,057	1,517,788
143	(589) Rents	12,478	7,126
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	6,483,089	5,736,531
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	7,501	18,315
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	240,657	168,580
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	5,300,636	7,116,837
150	(594) Maintenance of Underground Lines	379,829	354,051
151	(595) Maintenance of Line Transformers	80,026	69,504
152	(596) Maintenance of Street Lighting and Signal Systems	6,267	40,918
153	(597) Maintenance of Meters	266	150,922
154	(598) Maintenance of Miscellaneous Distribution Plant	9,930	41,445
155	TOTAL Maintenance (Total of Lines 146 thru 154)	6,025,112	7,960,572
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	12,508,201	13,697,103
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	77,347	68,534
160	(902) Meter Reading Expenses	161,410	130,079
161	(903) Customer Records and Collection Expenses	1,156,306	1,284,441
162	(904) Uncollectible Accounts	448,010	388,632
163	(905) Miscellaneous Customer Accounts Expenses	261,431	230,094
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	2,104,504	2,101,780
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	50,504	48,435
168	(908) Customer Assistance Expenses	548,897	590,139
169	(909) Informational and Instructional Expenses	6,977	8,080
170	(910) Miscellaneous Customer Service and Informational Expenses	1,206	975
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	607,584	647,629
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	2,709	1,671
176	(913) Advertising Expenses		5,913
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	2,709	7,584
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	13,933,613	15,162,616

182	(921) Office Supplies and Expenses		4,719,618	4,446,784
183	(Less) (922) Administrative Expenses Transferred-Credit		3,599,865	3,680,561
184	(923) Outside Services Employed		2,942,836	4,070,688
185	(924) Property Insurance		1,443,406	1,240,734
186	(925) Injuries and Damages		3,065,149	2,214,405
187	(926) Employee Pensions and Benefits		6,032,159	6,942,488
188	(927) Franchise Requirements			
189	(928) Regulatory Commission Expenses		1,035,201	901,817
190	(929) (Less) Duplicate Charges-Cr.		707,630	363,255
191	(930.1) General Advertising Expenses		376,213	311,978
192	(930.2) Miscellaneous General Expenses		1,146,795	750,006
193	(931) Rents		1,948,676	1,887,360
194	TOTAL Operation (Enter Total of Lines 181 thru 193)		32,336,171	33,885,060
195	Maintenance			
196	(935) Maintenance of General Plant		2,884,040	3,122,148
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)		35,220,211	37,007,208
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)		173,605,957	175,859,587

**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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the 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)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER			
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total (k+l+m) of Settlement (\$) (n)
1	PacifiCorp	OS	181				30,678					1,216,905		1,216,905
2	Altop Energy	OS					56					1,008		1,008
3	Basin Electric Power	OS					29,999					1,189,827		1,189,827
4	Brookfield	OS										(440)		(440)
5	<sup>141</sup> Cheyenne Light Fuel and Power	OS					2,890					34,900		34,900
6	<sup>141</sup> Cheyenne Light Fuel and Power - Happy Jack Wind	OS					27,936					1,474,981		1,474,981
7	<sup>141</sup> Cheyenne Light Fuel and Power Silver Sage Wind	OS					51,630					3,536,382		3,536,382
8	Citigroup	OS										267		267
9	Colorado Springs Utilities	OS					705					24,205		24,205
10	Constellation Power/Exelon	OS					60					840		840
11	Corriedale Wind	OS					129,589					3,640,682		3,640,682
12	Dynasty Power	OS					1,351					50,415		50,415
13	Energy Keepers	OS					240					23,700		23,700
14	Fall River Solar	OS					174,002					5,568,105		5,568,105
15	Guzman Energy	OS					53,972					4,211,953		4,211,953
16	Idaho Power	OS					105					370		370
17	Macquarie Energy	OS					19,161					1,362,500		1,362,500
18	MAG Energy	OS					430					16,700		16,700
19	Mercuria	OS					12,529					326,806		326,806
20	Morgan Stanley	OS					273					7,312		7,312
21	Municipal Energy Agency of Nebraska (MEAN)	OS										375		375
22	Northwestern Energy	OS					1,278					34,432		34,432
23	Phillips 66 Energy	OS					6,819					273,000		273,000
24	Platte River Power Authority	OS					3,572					199,236		199,236
25	Platte River Power Authority-Silver Sage Wind	OS					31,037					621,054		621,054
26	Portland General Electric	OS					25					1,625		1,625
27	Public Service Company of Colorado	OS					8,996					316,561		316,561
28	Public Service Company of New Mexico	OS					1,120					(1,646)		(1,646)
29	Rainbow Energy	OS					399					1,545		1,545
30	Salt River Project	OS					1,250					75,000		75,000
31	Southwest Power Pool	OS					96,195					761,048		761,048
32	Southwest Power Pool-WEIS	OS	SPP RTO										1,380,187	1,380,187
33	Spearfish, (City of) - Spearfish Hydro	OS					19,921					671,073		671,073



Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Affiliate transaction
(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Affiliate transaction
(c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Affiliate transaction
(d) Concept: EnergyReceivedThroughPowerExchanges
Deviation Power Exchange/Imbalance Charges
(e) Concept: EnergyDeliveredThroughPowerExchanges
Deviation Power Exchange/Imbalance Charges
(f) Concept: EnergyChargesOfPurchasedPower
Renewable Energy Customer Purchase Program
(g) Concept: OtherChargesOfPurchasedPower
Energy Imbalance Market
(h) Concept: OtherChargesOfPurchasedPower
Deviation Power Exchange/Imbalance Charges

**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 megawatt-hours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS				
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total Revenues (\$) (k+l+m) (n)	
1	Basin Electric Power	Black Hills Power	Black Hills Power	OS	12	RC DC Tie	RC DC		2,243	2,243	3,292,800				3,292,800
2	Black Hills Power	Black Hills Power	Black Hills Power	FNS	11	Various	Various		2,024,027	2,024,027		9,625,160	1,618,363	11,243,523	
3	Basin Electric Power	Black Hills Power	Basin Electric Power	FNO	11	Various	Various		2,134,750	2,134,750		8,999,906	1,530,267	10,530,173	
4	City of Gillette	Black Hills Power	City of Gillette	FNO	11	Various	Various		355,201	355,201		1,737,449	295,061	2,032,510	
5	South Dakota, State of	Black Hills Power	South Dakota State of	FNO	11	Various	Various		16,416	16,416		70,039	11,893	81,932	
6	Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power, Basin Electric Power	LFP	7	WYODAK	SGW	152	992,967	992,967	4,852,672		702,399	5,555,071	
7	MEAN	Black Hills Power	MEAN, Western Area Power Administration-LAP	LFP	7	WYODAK, WY69	SGW	35	64,145	64,145	1,117,391		161,632	1,279,023	
8	Basin Electric Power	Black Hills Power	Basin Electric Power	LFP	7	DRYFORK	RC	130	28,136	28,136	2,154,961		280,028	2,434,989	
9	Basin Electric Power	Black Hills Power	Wyoming Municipal Power Agency	LFP	7	DRYFORK	DJ	30	38,557	38,557	2,953,114		383,745	3,336,859	
10	Basin Electric Power	Black Hills Power	Basin Electric Power	SFP	7	DJ	RC		576	576		3,021	307	3,328	
11	Basin Electric Power	Black Hills Power	Basin Electric Power	SFP	7	DJ	WYODAK		53	53		278	28	306	
12	Basin Electric Power	Black Hills Power	Basin Electric Power	SFP	7	DRYFORK	DJ		518	518		2,716	277	2,993	
13	Basin Electric Power	Black Hills Power	Basin Electric Power	SFP	7	DRYFORK	SGW		16	16		83	9	92	
14	Basin Electric Power	Black Hills Power	Basin Electric Power	SFP	7	SGW	WYODAK		1,271	1,271		6,666	679	7,345	
15	Black Hills Power	Black Hills Power	Black Hills Power	SFP	7	SGW	RC		7	7		25	3	28	
16	MAG Energy Solutions	Black Hills Power	MAG Energy Solutions	SFP	7	RC	DJ		171	171		1,088	103	1,191	
17	PacifiCorp	Black Hills Power	PacifiCorp	SFP	7	WYODAK	WSTAR		9,036	9,036		33,084	4,466	37,550	
18	PacifiCorp	Black Hills Power	PacifiCorp	SFP	7	WSTAR	ANTELOPE		9,036	9,036		33,084	4,466	37,550	
19	Powerex Corp	Black Hills Power	Powerex Corp	SFP	7	DJ	RC		100	100		384	46	430	
20	Powerex Corp	Black Hills Power	Powerex Corp	SFP	7	RC	DJ		122	122		469	56	525	
21	Powerex Corp	Black Hills Power	Powerex Corp	SFP	7	RC	WYODAK		28	28		108	13	121	
22	The Energy Authority	Black Hills Power	The Energy Authority	SFP	7	RC	DJ		1,300	1,300		5,412	607	6,019	
23	TransAlta Energy Marketing U.S.Inc.	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	SFP	7	RC	DJ		200	200		726	89	815	
24	Altop Energy	Black Hills Power	Altop Energy	NF	8	DJ	RC		520	520		331	269	600	
25	Altop Energy	Black Hills Power	Altop Energy	NF	8	SGW	DJ		100	100		63	52	115	
26	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DJ	DRYFORK		66	66		42	35	77	
27	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DJ	RC		17	17		11	9	20	
28	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DJ	SGW		5,600	5,600		3,561	2,989	6,550	
29	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DJ	SHERIDAN		27	27		17	14	31	
30	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DJ	WYODAK		2,342	2,342		1,489	1,250	2,739	
31	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DRYFORK	DJ		149,378	149,378		95,000	79,721	174,721	
32	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DRYFORK	DRYFORK		45	45		29	24	53	
33	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DRYFORK	SGW		414,593	414,593		263,669	221,262	484,931	
34	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DRYFORK	WYODAK		2,671	2,671		1,699	1,425	3,124	
35	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	RC	SGW		1,034	1,034		657	552	1,209	
36	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	RC	WYODAK		1,142	1,142		726	609	1,335	
37	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	SGW	DJ		814	814		518	434	952	
38	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	SGW	DRYFORK		288	288		183	154	337	
39	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	SGW	RC		2,164	2,164		1,376	1,155	2,531	
40	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	SGW	SHERIDAN		444	444		282	237	519	
41	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	SGW	WYODAK		543	543		345	290	635	
42	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	WYODAK	RC		110	110		70	59	129	
43	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	WYODAK	SGW		2,051	2,051		1,304	1,095	2,399	
44	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	WYODAK	WYODAK		345	345		219	184	403	

45	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	DJ	RC		176,336	176,336		112,144	95,049	207,193
46	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	DJ	SGW		527	527		335	284	619
47	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	DJ	SHERIDAN		425	425		270	229	499
48	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	DJ	WYODAK		90	90		57	49	106
49	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	DRYFORK	DJ		428	428		272	231	503
50	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	DRYFORK	RC		5,616	5,616		3,572	3,027	6,599
51	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	DRYFORK	SGW		1,990	1,990		1,265	1,073	2,338
52	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	RC	DJ		3,058	3,058		1,945	1,648	3,593
53	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	RC	SGW		1,323	1,323		841	713	1,554
54	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	RC	SHERIDAN		1,074	1,074		683	579	1,262
55	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	RC	WYODAK		3,725	3,725		2,369	2,008	4,377
56	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	SGW	DJ		100	100		63	54	117
57	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	SGW	RC		59,904	59,904		38,097	32,289	70,386
58	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	SGW	SHERIDAN		360	360		229	194	423
59	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	SGW	WYODAK		7	7		4	4	8
60	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	SHERIDAN	SHERIDAN		331	331		211	178	389
61	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	WYODAK	DJ		204,726	204,726		130,200	110,351	240,551
62	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	WYODAK	RC		1,937	1,937		1,232	1,044	2,276
63	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	WYODAK	SGW		108,362	108,362		68,915	58,409	127,324
64	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	WYODAK	SHERIDAN		5,182	5,182		3,296	2,793	6,089
65	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	WYODAK	WYODAK		559	559		356	301	657
66	Black Hills Wyoming	Black Hills Power	Black Hills Wyoming	NF	8	DJ	WYODAK		60	60		38	34	72
67	Black Hills Wyoming	Black Hills Power	Black Hills Wyoming	NF	8	DRYFORK	DJ		10	10		6	6	12
68	Black Hills Wyoming	Black Hills Power	Black Hills Wyoming	NF	8	DRYFORK	SGW		14	14		9	8	17
69	Black Hills Wyoming	Black Hills Power	Black Hills Wyoming	NF	8	WYODAK	SGW		355	355		226	204	430
70	Black Hills Wyoming	Black Hills Power	Black Hills Wyoming	NF	8	WYODAK	WYODAK		45	45		29	25	54
71	Black Hills/Colorado Electric	Black Hills Power	Black Hills/Colorado Electric	NF	8	DRYFORK	DJ		20	20		13	10	23
72	Black Hills/Colorado Electric	Black Hills Power	Black Hills/Colorado Electric	NF	8	DRYFORK	SGW		20	20		13	10	23
73	Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power	NF	8	DJ	RC		20	20		13	10	23
74	Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power	NF	8	DJ	SGW		196	196		125	102	227
75	Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power	NF	8	DRYFORK	DJ		796	796		506	416	922
76	Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power	NF	8	DRYFORK	RC		15	15		10	7	17
77	Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power	NF	8	DRYFORK	SGW		2,917	2,917		1,855	1,525	3,380
78	Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power	NF	8	RC	DJ		135	135		86	70	156
79	Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power	NF	8	WYODAK	SGW		5,920	5,920		3,765	3,094	6,859
80	Dynasty Power Inc.	Black Hills Power	Dynasty Power Inc.	NF	8	DJ	RC		400	400		254	222	476
81	Dynasty Power Inc.	Black Hills Power	Dynasty Power Inc.	NF	8	RC	DJ		751	751		478	416	894
82	Dynasty Power Inc.	Black Hills Power	Dynasty Power Inc.	NF	8	RC	SGW		250	250		159	138	297
83	Dynasty Power Inc.	Black Hills Power	Dynasty Power Inc.	NF	8	RC	WYODAK		311	311		198	172	370
84	Dynasty Power Inc.	Black Hills Power	Dynasty Power Inc.	NF	8	SGW	DJ		18	18		11	10	21
85	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	DJ	RC		4,972	4,972		3,162	2,635	5,797
86	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	DJ	SGW		100	100		64	53	117
87	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	DJ	SHERIDAN		720	720		458	381	839
88	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	RC	DJ		11,947	11,947		7,598	6,332	13,930
89	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	RC	SGW		539	539		343	286	629
90	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	SGW	DJ		110	110		70	58	128
91	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	SGW	RC		150	150		95	79	174
92	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	SGW	SHERIDAN		1,762	1,762		1,121	934	2,055
93	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	SHERIDAN	DJ		711	711		452	377	829
94	Macquarie Energy LLC	Black Hills Power	Macquarie Energy LLC	NF	8	DJ	RC		574	574		365	316	681
95	Macquarie Energy LLC	Black Hills Power	Macquarie Energy LLC	NF	8	RC	DJ		56,529	56,529		35,951	31,075	67,026
96	MAG Energy Solutions	Black Hills Power	MAG Energy Solutions	NF	8	DJ	RC		6,778	6,778		4,311	3,513	7,824
97	MAG Energy Solutions	Black Hills Power	MAG Energy Solutions	NF	8	RC	DJ		1,220	1,220		776	632	1,408
98	MAG Energy Solutions	Black Hills Power	MAG Energy Solutions	NF	8	RC	WYODAK		125	125		79	65	144

99	MAG Energy Solutions	Black Hills Power	MAG Energy Solutions	NF	8	SGW	DJ		41	41		26	21	47
100	PacifiCorp	Black Hills Power	PacifiCorp	NF	8	WYODAK	DJ		1	1		1	1	2
101	PacifiCorp	Black Hills Power	PacifiCorp	NF	8	WYODAK	WYODAK		1,118	1,118		711	574	1,285
102	PacifiCorp	Black Hills Power	PacifiCorp	NF	8	WYODAK	WSTAR		7,936	7,936		5,047	4,073	9,120
103	PacifiCorp	Black Hills Power	PacifiCorp	NF	8	WYODAK	ANTELOPE		246	246		156	126	282
104	PacifiCorp	Black Hills Power	PacifiCorp	NF	8	WSTAR	DJ		7,936	7,936		5,047	4,073	9,120
105	Powerex Corp	Black Hills Power	Powerex Corp	NF	8	DJ	RC		2,048	2,048		1,302	1,056	2,358
106	Powerex Corp	Black Hills Power	Powerex Corp	NF	8	RC	DJ		29,983	29,983		19,067	15,462	34,529
107	Powerex Corp	Black Hills Power	Powerex Corp	NF	8	RC	WYODAK		4,621	4,621		2,939	2,383	5,322
108	Powerex Corp	Black Hills Power	Powerex Corp	NF	8	WYODAK	RC		20	20		13	10	23
109	Public Service Company of Colorado	Black Hills Power	Public Service Company of Colorado	NF	8	DJ	RC		13,634	13,634		8,671	6,976	15,647
110	Public Service Company of Colorado	Black Hills Power	Public Service Company of Colorado	NF	8	RC	DJ		21,350	21,350		13,578	10,924	24,502
111	Public Service Company of Colorado	Black Hills Power	Public Service Company of Colorado	NF	8	RC	SGW		9,496	9,496		6,039	4,859	10,898
112	Public Service Company of Colorado	Black Hills Power	Public Service Company of Colorado	NF	8	SGW	RC		10,154	10,154		6,458	5,195	11,653
113	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	DJ	RC		4,219	4,219		2,683	2,365	5,048
114	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	DRYFORK	DJ		50	50		32	28	60
115	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	DRYFORK	WYODAK		1	1		1	1	2
116	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	RC	DJ		4,069	4,069		2,588	2,281	4,869
117	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	RC	SGW		412	412		262	231	493
118	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	SGW	RC		493	493		314	276	590
119	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	WYODAK	RC		56	56		36	31	67
120	Shell Energy North America	Black Hills Power	Shell Energy North America	NF	8	DJ	RC		1,390	1,390		884	662	1,546
121	Shell Energy North America	Black Hills Power	Shell Energy North America	NF	8	RC	DJ		2,071	2,071		1,317	987	2,304
122	Shell Energy North America	Black Hills Power	Shell Energy North America	NF	8	RC	WSTAR		50	50		32	24	56
123	TEC Energy Inc	Black Hills Power	TEC Energy Inc	NF	8	RC	DJ		252	252		160	145	305
124	Tenaska Power Services Co	Black Hills Power	Tenaska Power Services Co	NF	8	DJ	RC		1,887	1,887		1,200	1,062	2,262
125	Tenaska Power Services Co	Black Hills Power	Tenaska Power Services Co	NF	8	RC	DJ		233	233		148	131	279
126	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	DJ	DRYFORK		2	2		1	1	2
127	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	DJ	RC		4,669	4,669		2,969	2,281	5,250
128	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	DJ	WSTAR		1	1		1		1
129	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	DRYFORK	DJ		10	10		6	5	11
130	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	DRYFORK	RC		1	1		1		1
131	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	RC	DJ		6,993	6,993		4,447	3,416	7,863
132	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	RC	SGW		1	1		1		1
133	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	RC	WSTAR		75	75		48	37	85
134	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	SGW	DJ		50	50		32	24	56
135	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	SHERIDAN	RC		100	100		64	49	113
136	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	SHERIDAN	ANTELOPE		1	1		1		1
137	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	WSTAR	DJ		75	75		48	37	85
138	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	WSTAR	SHERIDAN		1	1		1		1
139	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	ANTELOPE	DJ		1	1		1		1
140	TransAlta Energy Marketing U.S.Inc.	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	NF	8	DJ	RC		5,131	5,131		3,263	2,624	5,887
141	TransAlta Energy Marketing U.S.Inc.	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	NF	8	RC	DJ		5,775	5,775		3,673	2,954	6,627
142	TransAlta Energy Marketing U.S.Inc.	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	NF	8	RC	SGW		3,372	3,372		2,145	1,725	3,870
143	TransAlta Energy Marketing U.S.Inc.	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	NF	8	SGW	RC		970	970		617	496	1,113
144	TransAlta Energy Marketing U.S.Inc.	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	NF	8	SHERIDAN	DJ		37	37		24	19	43
145	TransAlta Energy Marketing U.S.Inc.	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	NF	8	WYODAK	RC		5	5		3	3	6
146	WestConnect	Black Hills Power	Dynasty Power Inc.	NF	8	SGW	DJ		7	7		4	5	9
147	WestConnect	Black Hills Power	Guzman Energy LLC	NF	8	DJ	RC		59	59		36	48	84
148	WestConnect	Black Hills Power	Guzman Energy LLC	NF	8	DJ	SGW		44	44		27	36	63
149	WestConnect	Black Hills Power	Guzman Energy LLC	NF	8	RC	DJ		100	100		62	82	144
150	WestConnect	Black Hills Power	Guzman Energy LLC	NF	8	SGW	RC		60	60		37	49	86
151	WestConnect	Black Hills Power	Powerex Corp	NF	8	RC	DJ		551	551		509	738	1,247
152	WestConnect	Black Hills Power	Powerex Corp	NF	8	RC	SGW		149	149		377	547	924
153	WestConnect	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	DJ	RC		2,541	2,541		1,082	3,045	4,127
154	WestConnect	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	RC	DJ		78	78		33	93	126

155	WestConnect	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	RC	SGW			336	336		143	403	546	
156	WestConnect	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	SGW	RC			328	328		140	393	533	
157	WestConnect	Black Hills Power	Shell Energy North America	NF	8	DJ	RC			200	200		103	204	307	
158	WestConnect	Black Hills Power	Shell Energy North America	NF	8	RC	DJ			1,202	1,202		617	1,229	1,846	
159	WestConnect	Black Hills Power	Shell Energy North America	NF	8	RC	SGW			190	190		98	194	292	
160	WestConnect	Black Hills Power	Shell Energy North America	NF	8	SGW	RC			1	1		1	1	2	
161	WestConnect	Black Hills Power	The Energy Authority	NF	8	RC	DJ			265	265		196	206	402	
162	WestConnect	Black Hills Power	The Energy Authority	NF	8	RC	SGW			560	560		413	435	848	
163	WestConnect	Black Hills Power	The Energy Authority	NF	8	SGW	DJ			1,200	1,200		886	933	1,819	
164	WestConnect	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	NF	8	DJ	RC			50	50		19	31	50	
165	WestConnect	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	NF	8	RC	DJ			13	13		5	8	13	
166	WestConnect	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	NF	8	RC	SGW			149	149		57	93	150	
167	WestConnect	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	NF	8	SGW	DJ			92	92		35	57	92	
168	WestConnect	Black Hills Power	Mercuria Energy America, LLC	NF	8	DJ	SGW			1,105	1,105		617	943	1,560	
169	<sup>(b)(5)</sup> Black Hills Power	Black Hills Power	Black Hills Power	AD										<sup>(b)(5)</sup> 341,524	341,524	
170	Basin Electric Power	Black Hills Power	Basin Electric Power	AD										<sup>(b)(5)</sup> 144,235	144,235	
171	<sup>(b)(5)</sup> Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power	AD										<sup>(b)(5)</sup> 176,886	176,886	
172	City of Gillette	Black Hills Power	City of Gillette	AD										<sup>(b)(5)</sup> 97,470	97,470	
173	South Dakota, State of	Black Hills Power	South Dakota State of	AD										<sup>(b)(5)</sup> 3,172	3,172	
174	<sup>(b)(5)</sup> Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power, Basin Electric Power	AD										<sup>(b)(5)</sup> (214,670)	(214,670)	
175	MEAN	Black Hills Power	MEAN, Western Area Power Administration-LAP	AD										<sup>(b)(5)</sup> (61,296)	(61,296)	
176	Basin Electric Power	Black Hills Power	Basin Electric Power	AD										<sup>(b)(5)</sup> (21,706)	(21,706)	
177	Basin Electric Power	Black Hills Power	Wyoming Municipal Power Agency	AD										<sup>(b)(5)</sup> 7,698	7,698	
178	<sup>(b)(5)</sup> Black Hills Power	Black Hills Power	Black Hills Power	AD										<sup>(b)(5)</sup> (9,840)	(9,840)	
179	Basin Electric Power	Black Hills Power	Basin Electric Power	AD										<sup>(b)(5)</sup> (15,673)	(15,673)	
180	<sup>(b)(5)</sup> Black Hills Wyoming	Black Hills Power	Black Hills Wyoming	AD										<sup>(b)(5)</sup> 33,454	33,454	
181	<sup>(b)(5)</sup> Black Hills/Colorado Electric	Black Hills Power	Black Hills/Colorado Electric	AD										<sup>(b)(5)</sup> (3)	(3)	
182	<sup>(b)(5)</sup> Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power	AD										<sup>(b)(5)</sup> (919)	(919)	
183	Altop Energy	Black Hills Power	Altop Energy	AD										<sup>(b)(5)</sup> (8)	(8)	
184	Dynasty Power Inc.	Black Hills Power	Dynasty Power Inc.	AD										<sup>(b)(5)</sup> (1,737)	(1,737)	
185	CP Energy Marketing (US) Inc (EEMU)	CP Energy Marketing (US) Inc	CP Energy Marketing (US) Inc	AD										<sup>(b)(5)</sup> (14)	(14)	
186	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	AD										<sup>(b)(5)</sup> (1,308)	(1,308)	
187	Mercuria Energy America, LLC (MEAI01)	Mercuria Energy America, LLC	Mercuria Energy America, LLC	AD										<sup>(b)(5)</sup> (1,100)	(1,100)	
188	Pacificorp	Black Hills Power	Pacificorp	AD										<sup>(b)(5)</sup> (46)	(46)	
189	Tenaska Power Services Co	Black Hills Power	Tenaska Power Services Co	AD										<sup>(b)(5)</sup> (18)	(18)	
190	Powerex Corp	Black Hills Power	Powerex Corp	AD										<sup>(b)(5)</sup> (2,638)	(2,638)	
191	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	AD										<sup>(b)(5)</sup> (1,788)	(1,788)	
192	Shell Energy North America	Black Hills Power	Shell Energy North America	AD										<sup>(b)(5)</sup> (140)	(140)	
193	MAG Energy Solutions	Black Hills Power	MAG Energy Solutions	AD										<sup>(b)(5)</sup> (664)	(664)	
194	Macquarie Energy LLC	Black Hills Power	Macquarie Energy LLC	AD										<sup>(b)(5)</sup> (465)	(465)	
195	The Energy Authority	Black Hills Power	The Energy Authority	AD										<sup>(b)(5)</sup> (168)	(168)	
196	TEC Energy Inc	Black Hills Power	TEC Energy Inc	AD										<sup>(b)(5)</sup> (5)	(5)	
197	TransAlta Energy Marketing U.S.Inc.	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	AD										<sup>(b)(5)</sup> (628)	(628)	
198	Public Service Company of Colorado	Black Hills Power	Public Service Company of Colorado	AD										<sup>(b)(5)</sup> (839)	(839)	
35	TOTAL									347	7,098,037	7,098,037	14,370,938	21,421,839	6,226,245	42,019,022

Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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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: PaymentByCompanyOrPublicAuthority Affiliate transaction
(ai) Concept: PaymentByCompanyOrPublicAuthority Affiliate transaction
(aj) Concept: PaymentByCompanyOrPublicAuthority Affiliate transaction
(ak) Concept: PaymentByCompanyOrPublicAuthority Affiliate transaction
(al) Concept: PaymentByCompanyOrPublicAuthority Affiliate transaction
(am) Concept: PaymentByCompanyOrPublicAuthority Affiliate transaction
(an) Concept: PaymentByCompanyOrPublicAuthority Affiliate transaction

(ao) Concept: PaymentByCompanyOrPublicAuthority
Affiliate transaction
(ap) Concept: PaymentByCompanyOrPublicAuthority
Affiliate transaction
(aq) Concept: PaymentByCompanyOrPublicAuthority
Affiliate transaction
(ar) Concept: PaymentByCompanyOrPublicAuthority
Affiliate transaction
(as) Concept: PaymentByCompanyOrPublicAuthority
Affiliate transaction
(at) Concept: TransmissionOfElectricityForOthersEnergyReceived
Losses received on RC DC Tie
(au) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Losses received on RC DC Tie
(av) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(aw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(ax) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(ay) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(az) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(ba) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bb) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(be) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bf) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bi) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bk) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bo) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(br) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bs) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bt) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bu) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(bx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up
(by) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Prior year true-up

Name of Respondent:  
Black Hills Power Inc.

This report is:  
(1)  An Original  
(2)  A Resubmission

Date of Report:  
12/31/2024

Year/Period of Report  
End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
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6					
7					
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43					
44					
45					
46					
47					
48					
49					
40	TOTAL				

**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	2,395	2,395				
2	PacifiCorp	FNS	307,507	307,507		1,260,752		1,260,752
3	PacifiCorp	LFP			1,118,517			1,118,517
4	PacifiCorp	NF	2,372,650	2,372,650				
5	Basin Electric	NF	22,496	22,496		33,646		33,646
6	Colorado River Storage	NF	3,220	3,220		7,160		7,160
7	Deseret Power	NF	65	65		482		482
8	Northwestern Energy	SFP	27	27		166		166
9	Public Service Company of Colorado	NF	677	677		3,971		3,971
10	Southwest Power Pool	NF	108,308	108,308		904,688		904,688
11	Tri-State Generation	NF	985	985		9,001		9,001
12	Western Area Power Loveland	NF	43,999	43,999		162,701		162,701
13	Western Area Power Administration	OS				320,767		320,767
14	<sup>(a)</sup> Common Use System	LFP	69,094	69,094	2,960,219			2,960,219
15	Transmission Accruals	OS				(959,114)		(959,114)
16	Western Area Power Administration	OS					3,004,005	3,004,005
17	<sup>(a)</sup> Common Use System	FNS	2,024,027	2,024,027		15,142,106	2,601,427	17,743,533
18	<sup>(a)</sup> Common Use System	NF	576,060	576,060		576,060	516,355	1,092,415
	<b>TOTAL</b>		<b>5,531,510</b>	<b>5,531,510</b>	<b>4,078,736</b>	<b>17,462,386</b>	<b>6,121,787</b>	<b>27,662,909</b>

(a) 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 Assessments.

(b) 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 Assessments.

(c) 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 Assessments.

(d) Concept: DemandChargesTransmissionOfElectricityByOthers

Rapid City DC Tie Transactions

(e) Concept: OtherChargesTransmissionOfElectricityByOthers

Regulation costs paid to Western Area Power Administration

(f) 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 Assessments.

(g) 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 Assessments.

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

**MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)**

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	22,400
2	Nuclear Power Research Expenses	0
3	Other Experimental and General Research Expenses	0
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	0
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than \$5,000	
6	Directors' Fees	530,518
7	Bank Fees	228,366
8	Travel	10,721
9	Amortization of Deferred Financing Costs	124,930
10	Business Promotions	21,125
11	Consulting Fees	51,380
12	Economic Development Costs	107,100
13	Software Service	15,741
14	Miscellaneous Other	34,514
46	TOTAL	1,146,795

Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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**Depreciation and Amortization of Electric Plant (Account 403, 404, 405)**

- 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).
- 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.
- 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.
- 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	13,826,759				13,826,759
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	7,772,805	31,627			7,804,432
7	Transmission Plant	6,826,321				6,826,321
8	Distribution Plant	14,885,616				14,885,616
9	Regional Transmission and Market Operation					
10	General Plant	7,349,426		528,400		7,877,826
11	Common Plant-Electric					
12	TOTAL	50,660,927	31,627	528,400		51,220,954

**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	Osage	816	60 years	22%	12.07%		
13	Wyodak	122,406	58 years	13%	2.86%		24 years
14	Neil Simpson II	201,089	60 years	14%	2.9%		28 years
15	Wygen III	143,884	60 years	13%	2.64%		40 years
16	Lange CT	32,429	44 years	5%	2.29%		30 years
17	Neil Simpson I CT	33,999	44 years	5%	2.56%		28 years
18	Ben French CT	23,233	44 years	13%	2.61%		14 years
19	Ben French Diesel CT	2,369	45 years	22%	5.06%		7 years
20	Cheyenne Prairie Generating Station	115,052	40 years	4%	2.98%		42 years
21	Corriedale Wind Farm	49,410	25 years	0%	4.28%		25 years
22	(352)Structures and Improvements	2,021	50 years	10%	1.83%		40 years
23	(353)Station Equipment	76,357	42 years	5%	2.13%		36 years
24	(354)Towers and Fixtures	940	60 years	20%	1.74%		56 years
25	(355)Poles and Fixtures	116,153	55 years	30%	2.74%		38 years
26	(356)Overhead Conductors and Devices	93,601	60 years	20%	2.05%		45 years
27	(359)Roads & Trails	7	60 years		1.72%		32 years
28	(361)Structures and Improvements	2,331	40 years	5%	2.45%		33 years
29	(362)Station Equipment	116,080	45 years	10%	2.27%		34 years
30	(364)Poles, Towers & Fixtures	124,768	50 years	70%	3.64%		37 years
31	(365)Overhead Conductor	71,164	50 years	20%	2.26%		39 years
32	(366)Underground Conduit	25,300	37 years	5%	2.81%		33 years
33	(367)Underground Conductors and Devices	88,967	40 years	5%	2.32%		30 years
34	(368)Line Transformers	73,946	36 years	0%	2.41%		27 years
35	(369)Services	42,711	62 years	50%	2.29%		51 years
36	(370)Meters	12,530	21 years	0%	5.23%		18 years
37	(371)Installation on Customer Premises	3,353	30 years	10%	3.22%		22 years
38	(373)Street Lighting	3,748	25 years	15%	3.96%		17 years
39	(390)Structures and Improvements	86,239	40 years	10%	1.67%		32 years
40	(391)Office Furniture and Equipment	14,967	10 years	0%	13.82%		6 years
41	(392)Transportation Equipment	30,144	13 years	10%	3.45%		11 years

42	(393)Stores Equipment	221	20 years	0%	9.32%	5 years
43	(394)Tools, Shop, & Garage Equipment	4,032	25 years	0%	3.33%	17 years
44	(395)Laboratory Equipment	742	25 years	0%	7.46%	13 years
45	(396)Power Operated Equipment	4,161	30 years	20%	1.28%	27 years
46	(397)Communication Equipment	6,754	20 years	0%	5.63%	14 years
47	(398)Miscellaneous Equipment	1,522	20 years	0%	5.8%	13 years
48	TOTAL	1,727,446				

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	13,826,759	-	-	-	13,826,759
3	Nuclear Production Plant	-	-	-	-	-
4	Hydraulic Production Plant- Conventional	-	-	-	-	-
5	Hydraulic Production Plant- Pumped Storage	-	-	-	-	-
6	Other Production Plant	7,772,805	31,627	-	-	7,804,432
7	Transmission Plant	6,584,894	-	-	-	6,584,894
8	Distribution Plant	14,885,615	-	-	-	14,885,615
9	Regional Transmission and Market Operation	-	-	-	-	-
10	General Plant	9,618,274	-	528,400	-	10,146,674
11	Common Plant-Electric	-	-	-	-	-
12	<b>TOTAL</b>	<b>52,688,347</b>	<b>31,627</b>	<b>528,400</b>	<b>-</b>	<b>53,248,374</b>

**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.

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)	EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
						CURRENTLY CHARGED TO				Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
						Department (f)	Account No. (g)	Amount (h)					
1	FERC Assessment	667,775		667,775		Reg Serv.	928						
2	Rate Case Expenses/Other		1,385	1,385						928			
3	Public Utilities Commission Assessments	362,335	97,676	460,011		Reg Serv.	588						
46	<b>TOTAL</b>	1,030,110	99,061	1,129,171					0			0	

**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:
 

<p>A. Electric R, D and D Performed Internally:</p> <ol style="list-style-type: none"> <li>1. Generation               <ol style="list-style-type: none"> <li>a. hydroelectric                   <ol style="list-style-type: none"> <li>i. Recreation fish and wildlife</li> <li>ii. Other hydroelectric</li> </ol> </li> <li>b. Fossil-fuel steam</li> <li>c. Internal combustion or gas turbine</li> <li>d. Nuclear</li> <li>e. Unconventional generation</li> <li>f. Siting and heat rejection</li> </ol> </li> <li>2. Transmission</li> </ol>	<ol style="list-style-type: none"> <li>a. Overhead</li> <li>b. Underground</li> <li>3. Distribution</li> <li>4. Regional Transmission and Market Operation</li> <li>5. Environment (other than equipment)</li> <li>6. Other (Classify and include items in excess of \$50,000.)</li> <li>7. Total Cost Incurred</li> </ol> <p>B. Electric, R, D and D Performed Externally:</p> <ol style="list-style-type: none"> <li>1. Research Support to the electrical Research Council or the Electric Power Research Institute</li> <li>2. Research Support to Edison Electric Institute</li> <li>3. Research Support to Nuclear Power Groups</li> <li>4. Research Support to Others (Classify)</li> <li>5. Total Cost Incurred</li> </ol>
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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		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
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Name of Respondent:  
Black Hills Power Inc.

This report is:  
(1)  An Original  
(2)  A Resubmission

Date of Report:  
12/31/2024

Year/Period of Report  
End of: 2024/ 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	4,638,222		4,638,222
4	Transmission	1,620,366		1,620,366
5	Regional Market	0		0
6	Distribution	2,983,653		2,983,653
7	Customer Accounts	819,697		819,697
8	Customer Service and Informational	306,651		306,651
9	Sales	103		103
10	Administrative and General	15,180,701		15,180,701
11	TOTAL Operation (Enter Total of lines 3 thru 10)	25,549,393		25,549,393
12	Maintenance			
13	Production	2,539,785		2,539,785
14	Transmission	65,370		65,370
15	Regional Market			
16	Distribution	1,241,419		1,241,419
17	Administrative and General	46,177		46,177
18	TOTAL Maintenance (Total of lines 13 thru 17)	3,892,751		3,892,751
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	7,178,007		7,178,007
21	Transmission (Enter Total of lines 4 and 14)	1,685,736		1,685,736
22	Regional Market (Enter Total of Lines 5 and 15)	0		0
23	Distribution (Enter Total of lines 6 and 16)	4,225,072		4,225,072
24	Customer Accounts (Transcribe from line 7)	819,697		819,697
25	Customer Service and Informational (Transcribe from line 8)	306,651		306,651
26	Sales (Transcribe from line 9)	103		103
27	Administrative and General (Enter Total of lines 10 and 17)	15,226,878		15,226,878
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	29,442,144		29,442,144
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminating 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 Terminating 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 Terminating 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	354,435		354,435
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	29,796,579		29,796,579
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	3,746,366		3,746,366
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	3,746,366		3,746,366
72	Plant Removal (By Utility Departments)			
73	Electric Plant	125,935		125,935
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	125,935		125,935
77	Other Accounts (Specify, provide details in footnote):			
78	Customer Accounts Receivable (142)	13,875		13,875
79	Accounts Receivable Third Party Billing (143)	4,212		4,212
80	Fuel Stock (151)	200		200
81	Stores Expense Undistributed (163)	760,123		760,123
82	Preliminary Surveys and Investigation Charges (183)	(84,286)		(84,286)
83	Clearing Accounts (184)	3,080,393		3,080,393
84	Misc Deferred Debits (186)	107		107
85	Accumulated provision for Pensions and Benefits (228.3)	(23,705)		(23,705)
86	Misc Current and Accrued Liabilities (242)	(144,908)		(144,908)
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,606,011		3,606,011
96	TOTAL SALARIES AND WAGES	37,274,891		37,274,891

Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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**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.

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**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)	446,140	571,878	864,500	1,380,187
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(732,294)	(1,306,834)	(2,276,308)	(2,648,952)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
46	TOTAL	(286,154)	(734,956)	(1,411,808)	(1,268,765)

**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.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant					
		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	4,065,632	KW/M	847,337	12,970,813	KW/M	2,657,376
2	Reactive Supply and Voltage	4,065,632	KW/M	1,495,114	12,970,813	KW/M	1,974,158
3	Regulation and Frequency Response	5,199	MW	3,004,006			
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other	2024026	MWH	775,330	5,977,838	MWH	1,594,711
8	Total (Lines 1 thru 7)	10,160,489		6,121,787	31,919,464		6,226,245

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FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnits FERC Annual Charge Assessment, WestConnect and True Ups
(b) Concept: AncillaryServicesPurchasedAmount FERC Annual Charge Assessment, WestConnect and True Ups

**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	1,029	15	7	325	373	347			116
2	February	969	15	12	286	353	347			125
3	March	875	23	11	266	318	347			107
4	Total for Quarter 1				877	1,044	1,041			348
5	April	786	29	8	232	267	347			109
6	May	768	26	12	202	270	347			231
7	June	800	24	17	355	324	347			152
8	Total for Quarter 2				789	861	1,041			492
9	July	884	29	15	355	303	347			528
10	August	955	6	18	332	326	347			135
11	September	869	3	17	349	320	347			125
12	Total for Quarter 3				1,036	949	1,041			788
13	October	751	31	9	253	299	347		12	75
14	November	874	20	9	276	397	347			195
15	December	878	20	10	298	329	347			15
16	Total for Quarter 4				827	1,025	1,041		12	285
17	Total				3,529	3,879	4,164		12	1,913

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12/31/2024

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End of: 2024/ 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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2024-12-31	Year/Period of Report End of: 2024/ Q4
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**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)	1,870,005
3	Steam	1,469,938	23	Requirements Sales for Resale (See instruction 4, page 311.)	225,420
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	464,217
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other	445,904	27	Total Energy Losses	71,215
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	1,915,842	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	2,630,858
10	Purchases (other than for Energy Storage)	802,744			
10.1	Purchases for Energy Storage				
11	Power Exchanges:				
12	Received	176,410			
13	Delivered	264,139			
14	Net Exchanges (Line 12 minus line 13)	(87,729)			
15	Transmission For Other (Wheeling)				
16	Received	7,098,037			
17	Delivered	7,098,037			
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	2,630,858			

**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	212,839	18,115	346	13	18
30	February	211,422	27,694	300	16	11
31	March	221,345	32,335	288	26	7
32	April	267,327	53,715	264	1	10
33	May	183,682	23,835	262	29	16
34	June	214,529	37,264	355	24	16
35	July	229,833	38,236	388	25	16
36	August	196,486	32,647	388	2	16
37	September	193,328	42,523	348	3	17
38	October	239,771	47,213	253	31	9
39	November	224,076	68,913	277	25	8
40	December	236,220	48,635	298	20	10
41	Total	2,630,858	471,125			

**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 term 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: Cheyenne Prairie Generating Station	Plant Name: Lange CT	Plant Name: Neil Simpson CT #1	Plant Name: Neil Simpson Unit 2	Plant Name: Wygen 3	Plant Name: 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		101		100	40	40	90	100.0	72.4
6	Net Peak Demand on Plant - MW (60 minutes)	10		98		60	38	37	84	57	69
7	Plant Hours Connected to Load	11		425		6,057	4,011	2,059	8,228	7,877	8,167
8	Net Continuous Plant Capability (Megawatts)	10		80		60	38	37	80	57	67
9	When Not Limited by Condenser Water								80	57	67
10	When Limited by Condenser Water								80	57	67
11	Average Number of Employees					18			40	36	110
12	Net Generation, Exclusive of Plant Use - kWh	(361,093)		8,475,996		269,212,000	115,379,280	53,154,000	607,752,000	347,666,000	509,845,000
13	Cost of Plant: Land and Land Rights			7,554		1,869,419	2,705		117,401		109,191
14	Structures and Improvements			1,458,009		5,859,969	614,225	372,278	36,252,596	10,971,119	9,102,799
15	Equipment Costs	2,369,080		21,773,118		108,443,289	31,813,993	33,615,276	164,819,658	132,915,676	113,232,558
16	Asset Retirement Costs										
17	Total cost (total 13 thru 20)	2,369,080		23,238,681		116,172,677	32,430,923	33,987,554	201,189,655	143,886,795	122,444,548
18	Cost per kW of Installed Capacity (line 17/5) Including	236.908		230.542		1,161.727	810.773	849.689	2,235.441	1,438.868	1,690.989
19	Production Expenses: Oper, Supv, & Engr	13,537		225,996		597,181	114,881	130,963	329,943	197,098	971,075
20	Fuel	4,687		354,037		5,224,663	4,847,416	2,209,821	10,348,186	5,859,428	6,952,251
21	Coolants and Water (Nuclear Plants Only)										
22	Steam Expenses								774,717	447,774	300,147
23	Steam From Other Sources										
24	Steam Transferred (Cr)										
25	Electric Expenses	34,051		96,489		696,578	159,302	240,736	367,969	253,258	
26	Misc Steam (or Nuclear) Power Expenses	285		285			285		605,655	334,276	519,978
27	Rents					763,561	580,635	955,215	1,447,398	2,286,968	
28	Allowances										
29	Maintenance Supervision and Engineering	218		218		31	272		573,085	235,527	(1,689)
30	Maintenance of Structures			238				3	508,079	319,143	
31	Maintenance of Boiler (or reactor) Plant								2,836,877	1,713,610	1,027,060
32	Maintenance of Electric Plant	30,876		267,114		1,074,680	681,790	337,896	817,027	238,442	163,568
33	Maintenance of Misc Steam (or Nuclear) Plant								25,116	22,659	33,140
34	Total Production Expenses	83,654		944,377		8,356,694	6,384,581	3,874,634	18,634,052	11,908,183	9,965,530
35	Expenses per Net kWh			0.1114		0.0310	0.0553	0.0729	0.0307	0.0343	0.0195

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	108	135,738	41	2,142,738	1,180,444	571,163	491,083	11,034	258,812	13,334	299,022
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	134,775	1,092	133,811	1,050	1,095	1,098	7,920	1,098	7,926	1,098	7,912
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	79.77	4.36	350.46	2.44	3.87	3.87	17.20	4.08	17.11	4.02	20.06
41	Average Cost of Fuel per Unit Burned	79.77	4.36	350.46	2.44	3.85	3.87	21.07	4.08	22.23	4.02	23.25
42	Average Cost of Fuel Burned per Million BTU	14.09	3.99		2.32	3.75	3.52	1.32	3.72	1.40	7.31	1.47
43	Average Cost of Fuel Burned per kWh Net Gen		0.069		0.019	0.039	0.042	0.003	7.411	0.004	0.207	0.014

44	Average BTU per kWh Net Generation	8,757	8,357	11,203	11,798	12,799	11,801	9,281
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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 Gillette, 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	<b>Net Plant Capability (in megawatts)</b>					
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	<b>Cost of Plant</b>					
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	<b>Production Expenses</b>					
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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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**Pumped Storage Generating Plant Statistics**

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

Line No.	Item (a)	FERC Licensed Project No. 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 Demand 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	<b>Cost of Plant</b>				
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	<b>Production Expenses</b>				
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))				

**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		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l))	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
1	Corriedale Wind Farm	2020	52.5	32.0	129,604,800	50,192,727	3.87	274,398		337	Wind		Wind

Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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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.

**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																			
2																			
3																			
4																			
5																			
6																			
7																			
8																			
9																			
10																			
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31																			
32																			
33																			
34																			
35	TOTAL																		

Name of Respondent:  
Black Hills Power Inc.

This report is:  
(1)  An Original  
(2)  A Resubmission

Date of Report:  
12/31/2024

Year/Period of Report  
End of: 2024/ 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									
2									
3									
4									
5									
6									
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31									
32									
33									
34									
35									
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)
1	Wyodak	Lookout	230.00	230.00	H-Wood	11.03		1	1272 KCM ACSR	9,800	5,836,586	5,846,386				
2	Lookout	Lange	230.00	230.00	H-Wood	54.53		1	1272 KCM ACSR	105,653	17,010,018	17,115,671				
3	Lange	West Hill	230.00	230.00	H-Wood	2.70		1	1272 KCM ACSR		3,563,100	3,563,100				
4	West Rapid Tap	West Rapid	230.00	230.00	SP-Steel	0.70		2	1272 KCM ACSR							
5	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				
6	South Rapid	West Hill	230.00	230.00	H-Wood	47.50		1	1272 KCM ACSR		11,863,841	11,863,841				
7	West Hill	Fall River	230.00	230.00	H-Wood	22.75		1	1272 KCM ACSR	17,701	9,038,121	9,055,822				
8	Fall River	Stegall	230.00	230.00	H-Wood	11.33		1	1272 KCM ACSR		365,570	365,570				
9	West Hill	Minnekahta	230.00	230.00	H-Wood	9.48		1	1272 KCM ACSR		965,072	965,072				
10	Minnekahta	Osage	230.00	230.00	H-Wood	23.32		1	1272 KCM ACSR	151,235	2,544,420	2,695,655				
11	Lange	Ben French	69.00	69.00	H-Wood	3.04		2	795 KCM ACSR	44,950	4,530,305	4,575,255				
12	DC Tie West	South Rapid City	230.00	230.00	SP-Steel	4.00		1	1272 KCM ACSR	127,145	630,238	757,383				
13	Osage	Yellowcreek	230.00	230.00	H-Wood	21.12		1	1272 KCM ACSR	1,533	273,459	274,992				
14	Osage	Lange	230.00	230.00	H-Wood	46.02		1	1272 KCM ACSR	1,512,324	24,476,372	25,988,696				
15	Wyodak	Lookout	230.00	230.00	H-Wood	73.26		1	1272 KCM ACSR	(363,530)	29,068,508	28,704,978				
16	Osage	Minnekahta	230.00	230.00	H-Wood	33.94		1	1272 KCM ACSR	96,159	2,936,535	3,032,694				
17	Osage	Wyodak	230.00	230.00	H-Wood	57.46		1	1272 KCM ACSR	162,516	4,780,594	4,943,110				
18	Neil Simpson I	Neil Simpson II	69.00	69.00	SP-Steel	0.80		1	795 KCM ACSR		304,794	304,794				
19	Osage	Yellowcreek	230.00	230.00	H-Wood	22.02		1	1272 KCM ACSR	13,308	292,380	305,688				
20	Neil Simpson I	Wyodak	69.00	69.00	H-Wood	0.29		1	795 KCM ACSR		180,434	180,434				
21	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				
22	Wygen 3	Donkey Creek	230.00	230.00	SP-Steel	0.76		1	1272 KCM ACSR	3,488	296,454	299,942				
23	Pumpkin Buttes	Windstar	230.00	230.00	H-Steel	68.20		1	1272 KCM ACSR	2,204,209	13,657,908	15,862,117				
24	Windstar	Dave Johnston	230.00	230.00	H-Steel	2.56		1	1272 KCM ACSR		686,732	686,732				
25	Donkey Creek	Wyodak Tie Line #2	230.00	230.00	Steel	1.06		2	1272 KCM ACSR		989,158	989,158				
26	WY 1.14 Tap	Wyodak Baghouse	230.00	230.00	H-Wood	0.10		1	336.4 ACSR		4,359	4,359				
27	Teckla	Osage	230.00	230.00	H-Wood	81.55		1	1272 KCM ACSR	2,467,545	24,670,433	27,137,978				
28	Osage	Lange	230.00	230.00	H-Wood	19.27		1	1272 KCM ACSR	589,324	10,387,094	10,976,418				
29	Fall River	Stegall	230.00	230.00	H-Wood	94.47		1	1272 KCM ACSR	329,367	23,299,206	23,628,573				
36	TOTAL					768		32		9,701,205	210,355,067	220,056,272				

Name of Respondent: Black Hills Power Inc.	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

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

**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																

**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 (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.  
 6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVA)			Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVA) (c)	Secondary Voltage (In MVA) (d)	Tertiary Voltage (In MVA) (e)				Type of Equipment (i)	Number of Units (j)	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 24 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	Merrillat, 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

**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	<b>Non-power Goods or Services Provided by Affiliated</b>			
2	<sup>(a)</sup> Allocation of direct and indirect costs provided by BHSC	<sup>(b)</sup> Black Hills Service Company	Various	55,988,056
3	<sup>(a)</sup> Allocation of Cheyenne Prairie Generating Station costs	Cheyenne Light, Fuel and Power	Various	3,413,138
4	Rent expense from Gillette Energy Complex shared facilities agreement	<sup>(a)</sup> Cheyenne Light, Fuel and Power	507.0	379,241
5	Rent expense from Gillette Energy Complex shared facilities agreement	<sup>(a)</sup> Black Hills Wyoming	507.0	16,387
6	Costs under spare turbine agreements	Cheyenne Light, Fuel and Power	550.0	670,540
7	Costs under spare turbine agreements	Black Hills Colorado IPP	550.0	93,021
8	Wygen III ground lease with WRDC	Wyodak Resources Development Corp.	507.0	1,200,442
9				
19				
20	<b>Non-power Goods or Services Provided for Affiliated</b>			
21	<sup>(a)</sup> Allocation of Gillette Energy Complex shared facilities costs	<sup>(b)</sup> Cheyenne Light, Fuel and Power	Various	2,287,112
22	<sup>(a)</sup> Allocation of Gillette Energy Complex shared facilities costs	<sup>(b)</sup> Black Hills Wyoming	417.1	2,355,787
23	<sup>(a)</sup> Allocation of Corriedale Wind Farm costs	Cheyenne Light, Fuel and Power	Various	381,547
24	Gillette Energy Complex rent revenue	<sup>(a)</sup> Cheyenne Light, Fuel and Power	454.0	1,472,048
25	Gillette Energy Complex rent revenue	<sup>(a)</sup> Black Hills Wyoming	454.0	1,776,011
26	Rent revenue from Horizon Point facility	Black Hills Service Company	454.0	11,434,740
27	Revenue from affiliates under spare turbine agreements	Cheyenne Light, Fuel and Power	454.0	1,734,156
28	Revenue from affiliates under spare turbine agreements	Black Hills Colorado IPP	417.4	1,191,877
29				
42				

FOOTNOTE DATA

(a) Concept: DescriptionOfNonPowerGoodOrService

<b>Indirect -</b>	
Operating Revenues (400)	(34,302)
Operation Expenses (401)	35,825,882
Maintenance Expenses (402)	2,972,286
Depreciation Expense (403)	4,184,058
Amort. & Depl. of Utility Plant (404-405)	535,534
Taxes Other Than Income Taxes (408.1)	1,108,729
Taxes Other Than Income Taxes (408.2)	1,357
Revenues From Merchandising, Jobbing and Contract Work (415)	(29,850)
(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)	16,699
(Less) Expenses of Nonutility Operations (417.1)	14,012
Donations (426.1)	67,944
Exp. for Certain Civic, Political & Related Activities (426.4)	116,210
Miscellaneous Nonoperating Income (421)	(54,636)
Penalties (426.3)	151
Other Deductions (426.5)	286,702
Revenues	(64,152)
Expenses	45,074,909
	45,010,757
<b>Direct -</b>	
Operating Revenues (400)	(15,338)
Operation Expenses (401)	6,393,042
Maintenance Expenses (402)	4,273,322
Taxes Other Than Income Taxes (408.1)	94,204
Taxes Other Than Income Taxes (408.2)	803
(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)	2,138
(Less) Expenses of Nonutility Operations (417.1)	21,687
Donations (426.1)	40,361
Exp. for Certain Civic, Political & Related Activities (426.4)	167,114
Miscellaneous Nonoperating Income (421)	(84)
Other Deductions (426.5)	50
Revenues	(15,338)
Expenses	10,992,637
	10,977,300

(b) Concept: DescriptionOfNonPowerGoodOrService

<b>Allocation from CLFP:</b>	
Operation Expenses (401)	2,268,848.00
Maintenance Expenses (402)	1,074,921.00
Taxes Other Than Income Taxes (408.1)	69,409.00
Allowance for Other Funds Used During Construction (419.1)	(21.00)
(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)	(19.00)
	3,413,138.00

(c) Concept: NameOfAssociatedAffiliatedCompany  
 Black Hills Power has 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.

(d) Concept: NameOfAssociatedAffiliatedCompany

Black Hills Power and Cheyenne Light Fuel and Power have a shared facilities agreement regarding the assets located at the Gillette, Wyoming energy complex. Each entity is charged for costs based on generating capacity.

(e) Concept: NameOfAssociatedAffiliatedCompany

Black Hills Power and Cheyenne Light Fuel and Power have a shared facilities agreement regarding the assets located at the Gillette, Wyoming energy complex. Each entity is charged for costs based on generating capacity.

(f) Concept: DescriptionOfNonPowerGoodOrService

<b>Allocation to CLFP:</b>	
Operation Expenses (401)	1,174,540.00
Maintenance Expenses (402)	1,052,179.00
Taxes Other Than Income Taxes (408.1)	60,318.00
Donations (426.1)	75.00
Total	2,287,112.00

(g) Concept: DescriptionOfNonPowerGoodOrService

**Allocation to BHW:**

(Less) Expenses of Nonutility Operations (417.1)	2,355,787.00
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(h) Concept: DescriptionOfNonPowerGoodOrService

<b>Allocation to CLFP:</b>	
Operation Expenses (401)	380,408
Maintenance Expenses (402)	722
Taxes Other Than Income Taxes (408.1)	417
Total	381,547

(i) Concept: NameOfAssociatedAffiliatedCompany

Black Hills Power and Cheyenne Light Fuel and Power have a shared facilities agreement regarding the assets located at the Gillette, Wyoming energy complex. Each entity is charged for costs based on generating capacity.

(j) Concept: NameOfAssociatedAffiliatedCompany

Black Hills Power and Cheyenne Light Fuel and Power have a shared facilities agreement regarding the assets located at the Gillette, Wyoming energy complex. Each entity is charged for costs based on generating capacity.

(k) Concept: NameOfAssociatedAffiliatedCompany

Black Hills Power and Cheyenne Light Fuel and Power have a shared facilities agreement regarding the assets located at the Gillette, Wyoming energy complex. Each entity is charged for costs based on generating capacity.

(l) Concept: NameOfAssociatedAffiliatedCompany

Black Hills Power and Cheyenne Light Fuel and Power have a shared facilities agreement regarding the assets located at the Gillette, Wyoming energy complex. Each entity is charged for costs based on generating capacity.

FERC FORM NO. 1 (NEW)