

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: 2025/ 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:
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-fags-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 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, utilizing, 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. § 825o(a).

**FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER**

IDENTIFICATION

01 Exact Legal Name of Respondent Black Hills Power Inc.		02 Year/ Period of Report End of: 2025/ Q4
03 Previous Name and Date of Change (If name changed during year) /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 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) 14103 Denver West Parkway, Suite 100, Lakewood, CO 80401-3124		
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) 12/31/2025

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) 04/02/2026
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.

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 and Environmental Credits	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	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	
63.1	Renewable Generating Plant Statistics	404	Not applicable
64	Hydroelectric Generating Plant Statistics	406	Not applicable
65	Pumped Storage Generating Plant Statistics	408	
66	Generating Plant Statistics Pages	410	
66.1	Energy Storage Operations (Large Plants)	414	
66.2	Energy Storage Operations (Small Plants)	419	
67	Transmission Line Statistics Pages	422	
68	Transmission Lines Added During Year	424	
69	Substations	426	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports (check appropriate box)		Not Prepared
	Stockholders' Reports Check appropriate box: <input type="checkbox"/> Two copies will be submitted <input 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: 12/31/2025	Year/Period of Report End of: 2025/ 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 0 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: 12/31/2025	Year/Period of Report End of: 2025/ 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, 2025, 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: 12/31/2025	Year/Period of Report End of: 2025/ 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	1,000,000		
2	Sr. Vice President and Chief Financial Officer	Kimberly F. Nooney	490,000		
3	Sr. Vice President and General Counsel	Phillip A. Casey	405,000		2025-04-01
4	Sr. Vice President - Chief Human Resources Officer	Sarah A. Wiltse	364,000		
5	Sr. Vice President - Chief Utility Officer	Marne M. Jones	490,000		
6	Sr. Vice President - Chief Information Officer	Erik D. Keller	413,000		2025-02-28
7	Vice President - Black Hills Energy South Dakota and Wyoming	Wes Ashton	268,702		
8	Sr. Vice President - Chief Information and Transformation Officer	Don Redden	390,000	2025-07-21	
9	Sr. Vice President - Chief Legal Officer and Corporate Secretary	Darren Nakata	430,000	2025-10-13	

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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	Marne M. Jones (Sr. Vice President - Chief Utility Officer)	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, ER25-1798-001

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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.

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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	20250227-5283	02/27/2025	ER25-1441-000	Informational Filing of 2025 Formula Rate Annual Update of Black Hills Power, Inc. under ER25-1441	Attachment H

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: 12/31/2025	Year/Period of Report End of: 2025/ 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. See Schedule 122, Notes to Financial Statements, for information regarding the pending merger between Black Hills Corporation and Northwestern Energy.

3. None

4. None

5. None

6. None

7. None

8. The average union wage increase for Black Hills Power for 2025 was 4.8%. The average non-union wage increase for Black Hills Power for 2025 was 5.2%.

9. None.

10. None

12. None

13. The following officer and director changes occurred during the year:
- Erik D. Keller, Senior Vice President – Chief Information Officer, resigned effective February 28, 2025.
 - Katie Fleming was appointed to Vice President – Customer Experience and Chief Sustainability Officer effective March 31, 2025.
 - Phillip A. Casey, Senior Vice President – Chief Legal Officer, General Counsel and Assistant Corporate Secretary was removed as an officer effective April 1, 2025.
 - Mame M. Jones was appointed Director effective April 23, 2025.
 - Amy K. Koenig, Vice President – Governance, Corporate Secretary and Deputy General Counsel, resigned effective May 1, 2025.
 - Don Redden was appointed Senior Vice President – Chief Information and Transformation Officer effective July 21, 2025.
 - Chris Herbers was appointed Vice President – Strategic Growth effective August 25, 2025.
 - Darren Nakata was appointed Senior Vice President – Chief Legal Officer, Corporate Secretary and Chief Compliance Officer effective October 13, 2025.

14. None.

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200	1,875,661,461	1,810,191,675
3	Construction Work in Progress (107)	200	175,318,530	52,908,341
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		2,050,979,991	1,863,100,016
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	578,246,183	551,839,174
6	Net Utility Plant (Enter Total of line 4 less 5)		1,472,733,808	1,311,260,842
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)		1,472,733,808	1,311,260,842
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)			
19	(Less) Accum. Prov. for Depr. and Amort. (122)			
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances and Environmental Credits	228		
24	Other Investments (124)		1,150,900	1,158,472
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		2,858,548	2,788,134
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)		4,009,448	3,946,606
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		743,981	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)		15,532,156	18,312,575
41	Other Accounts Receivable (143)		1,859,695	2,502,050
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		114,176	108,493
43	Notes Receivable from Associated Companies (145)			12,018
44	Accounts Receivable from Assoc. Companies (146)		11,279,211	10,032,836
45	Fuel Stock (151)	227	5,958,241	7,095,782
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	35,661,220	34,033,429
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances and Environmental Credits (158.1, 158.2, 158.3, and 158.4)	228		
53	(Less) Noncurrent Portion of Allowances and Environmental Credits	228		
54	Stores Expense Undistributed (163)	227	2,376,838	3,454,259

55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		4,630,741	4,487,867
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)		13,436,280	12,183,417
62	Miscellaneous Current and Accrued Assets (174)			
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)		91,364,187	92,038,886
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		1,718,733	1,851,623
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	103,502,033	82,238,548
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)		529,872	618,641
76	Clearing Accounts (184)		1,544,979	1,571,121
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	5,696,622	5,515,791
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)			
82	Accumulated Deferred Income Taxes (190)	234	45,701,038	46,055,939
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		158,693,277	137,851,663
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,726,800,720	1,545,097,997

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	Credit Carryovers	\$	15,763,131	\$	16,198,219
3	Depreciation	\$	2,079,133	\$	2,272,462
4	Employee benefit plans	\$	1,656,940	\$	1,710,734
5	Net Operating Loss Carryforward			\$	-
6	Regulatory Assets	\$	21,059,500	\$	21,141,005
7	Other	\$	4,386,775	\$	3,784,760
8					
9	TOTAL Electric (Enter Total of lines 2 thru 7)	\$	44,945,479	\$	45,107,178
10	Gas				
11					
12	Other				
13	TOTAL Gas (Enter Total of lines 10 thru 15)				
14					
15	Other (Specify)				
16	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	\$	44,945,479	\$	45,107,178

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250	23,416,396	23,416,396
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		42,076,811	42,076,811
7	Other Paid-In Capital (208-211)	253	15,000,000	
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	586,627,226	541,942,205
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)	(658,522)	(652,595)
16	Total Proprietary Capital (lines 2 through 15)		663,960,029	604,280,935
17	LONG-TERM DEBT			
18	Bonds (221)	256	340,000,000	340,000,000
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256	248,450,000	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)		57,270	61,410
24	Total Long-Term Debt (lines 18 through 23)		588,392,730	536,388,590
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		12,459,182	12,854,745
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		406,026	2,103,976
29	Accumulated Provision for Pensions and Benefits (228.3)		9,536,635	9,242,324
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)		885,452	858,737
35	Total Other Noncurrent Liabilities (lines 26 through 34)		23,287,295	25,059,782
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)			
38	Accounts Payable (232)		46,035,496	22,096,000
39	Notes Payable to Associated Companies (233)		41,801,955	4,742,176
40	Accounts Payable to Associated Companies (234)		41,249,440	41,604,688
41	Customer Deposits (235)		2,399,763	1,464,322
42	Taxes Accrued (236)	262	12,311,849	9,909,222
43	Interest Accrued (237)		4,727,117	4,704,700
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		1,059,689	993,793
48	Miscellaneous Current and Accrued Liabilities (242)		6,651,838	5,816,766
49	Obligations Under Capital Leases-Current (243)		352,617	357,621
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)		156,589,764	91,689,288
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		8,486,663	7,692,422
57	Accumulated Deferred Investment Tax Credits (255)	266		
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	1,125,704	1,638,914
60	Other Regulatory Liabilities (254)	278	90,756,587	94,110,133
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		170,304,918	164,913,424
64	Accum. Deferred Income Taxes-Other (283)		23,897,030	19,324,509
65	Total Deferred Credits (lines 56 through 64)		294,570,902	287,679,402
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,726,800,720	1,545,097,997

16	TOTAL (Acct 283) (Enter Total of lines 12, 20, and 21)	17,423,866	2,316,340	1,087,120						
17	Classification of TOTAL									
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									

32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,519,609	1,066,941															
33	Revenues From Nonutility Operations (417)		2,236,719	1,946,155															
34	(Less) Expenses of Nonutility Operations (417.1)		185,111	45,461															
35	Nonoperating Rental Income (418)																		
36	Equity in Earnings of Subsidiary Companies (418.1)	119																	
37	Interest and Dividend Income (419)		2,005,576	2,251,660															
38	Allowance for Other Funds Used During Construction (419.1)		4,129,473	21															
39	Miscellaneous Nonoperating Income (421)		121,386	149,042															
40	Gain on Disposition of Property (421.1)		1,166,939	358,340															
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		10,156,433	4,475,676															
42	Other Income Deductions																		
43	Loss on Disposition of Property (421.2)																		
44	Miscellaneous Amortization (425)																		
45	Donations (426.1)		278,730	231,441															
46	Life Insurance (426.2)																		
47	Penalties (426.3)			151															
48	Exp. for Certain Civic, Political & Related Activities (426.4)		260,622	282,665															
49	Other Deductions (426.5)		1,327,135	353,679															
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,866,487	867,936															
51	Taxes Applic. to Other Income and Deductions																		
52	Taxes Other Than Income Taxes (408.2)	262	33,436	29,852															
53	Income Taxes-Federal (409.2)	262	191,337	(37,445)															
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)		224,773	(7,593)															
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		8,065,173	3,615,333															
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															
65	(Less) Amort. of Premium on Debt-Credit (429)																		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)																		
67	Interest on Debt to Assoc. Companies (430)		13,922,110	13,364,648															
68	Other Interest Expense (431)		10,954	806,153															
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,452,855	996,669															
70	Net Interest Charges (Total of lines 62 thru 69)		31,894,571	33,717,274															
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		54,685,021	58,398,395															
72	Extraordinary Items																		
73	Extraordinary Income (434)																		
74	(Less) Extraordinary Deductions (435)																		
75	Net Extraordinary Items (Total of line 73 less line 74)																		
76	Income Taxes-Federal and Other (409.3)	262	0																
77	Extraordinary Items After Taxes (line 75 less line 76)																		
78	Net Income (Total of line 71 and 77)		54,685,021	58,398,395															

FOOTNOTE DATA

(a) Concept: IncomeTaxesOperatingIncome

Note: Below is the income tax as adjusted with the income tax effect of non-operating interest expense

Taxes as booked on FERC:	
Income Taxes- 409.1	(956,714)
Net Interest Expense - Total	31,894,571
Net Interest Expense Already Accounted for in Income Tax	-
Non-Operating Net Interest Expense Needing an Income Tax Adj	31,894,571
Remove Income Tax Effect of Non-Operating Interest Expense	(6,697,860)
Income Taxes- 409.1 As Adjusted	5,741,146

(b) Concept: IncomeTaxesUtilityOperatingIncomeOther

Note: Below is the income tax as adjusted with the income tax effect of non-operating interest expense

Taxes as booked on FERC:	
Income Taxes- 409.1	(956,714)
Net Interest Expense - Total	31,894,571
Net Interest Expense Already Accounted for in Income Tax	-
Non-Operating Net Interest Expense Needing an Income Tax Adj	31,894,571
Remove Income Tax Effect of Non-Operating Interest Expense	(6,697,860)
Income Taxes- 409.1 As Adjusted	5,741,146

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		541,942,205	526,043,810
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		(10,000,000)	(42,500,000)
15	TOTAL Debits to Retained Earnings (Acct. 439)		(10,000,000)	(42,500,000)
16	Balance Transferred from Income (Account 433 less Account 418.1)		54,685,021	58,398,395
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, Unappropriated Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		586,627,226	541,942,205
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)		586,627,226	541,942,205
	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)	54,685,021	58,398,395
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	51,735,557	50,693,987
5	Amortization of (Specify) (footnote details)	745,725	650,730
5.1	Amortization of utility plant	622,589	528,400
5.2	Amortization of plant acquisition adjustments	96,421	96,421
5.3	Accretion of Asset Retirement Obligation	26,715	25,909
8	Deferred Income Taxes (Net)	2,884,168	3,312,965
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	1,854,092	(987,562)
11	Net (Increase) Decrease in Inventory	587,171	(878,902)
12	Net (Increase) Decrease in Allowances and Environmental Credits Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	(1,112,111)	(5,055,490)
14	Net (Increase) Decrease in Other Regulatory Assets	(16,017,387)	(7,888,012)
15	Net Increase (Decrease) in Other Regulatory Liabilities		
16	(Less) Allowance for Other Funds Used During Construction	4,129,473	21
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	(3,727,914)	1,589,220
18.1	Bad debt expense	414,133	448,010
18.2	Deferred financing cost amortization	201,362	330,142
18.3	Employee benefit plan expense	742,339	566,478
18.4	Gain on disposition of property	(1,166,939)	(358,340)
18.5	Change in regulatory assets and liabilities impacting income statement	(1,813,924)	607,925
18.6	Changes in other current and non-current assets	(53,565)	633,865
18.7	Changes in other current and non-current liabilities	(2,051,320)	(638,860)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	87,504,849	99,835,310
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(181,033,814)	(82,890,254)
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	2,452,855	996,669
31	Other (provide details in footnote):	2,939,862	2,486,478
31.1	Cost of removal net of salvage	1,709,332	450,613
31.2	Contributions in aid of construction	1,293,372	2,105,026
31.3	Other investments	(62,842)	(69,161)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(180,546,807)	(81,400,445)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		

49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances and Environmental Credits 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)	(180,546,807)	(81,400,445)
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):	93,752,793	24,098,281
67.1	Net Borrowings from Money Pool	36,752,793	17,598,281
67.2	Net Borrowings of Notes Payable to Parent	52,000,000	6,500,000
67.3	Contribution from Parent	5,000,000	
70	Cash Provided by Outside Sources (Total 61 thru 69)	93,752,793	24,098,281
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)
76.1	Dividend to Parent		(42,500,000)
76.2	Net Payments to Money Pool		
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)	93,752,793	(18,401,719)
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)	710,835	33,146
88	Cash and Cash Equivalents at Beginning of Period	33,146	
90	Cash and Cash Equivalents at End of Period	743,981	33,146

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: 12/31/2025	Year/Period of Report End of: 2025/ 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 a 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 interim 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, where 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.

The Company has experienced negative cash flows, insufficient liquidity, and working capital to fund operations. The Company is also dependent upon financial support from its Parent in order to obtain and renew debt financing. As of December 31, 2025, the Company had \$40.7 million of outstanding short-term Money pool notes payable. These conditions and events raise substantial doubt about the Company's ability to continue as a going concern.

In response to these conditions, the Company's Parent, has committed to fully support the Company's operating, investing, and financing activities to enable the Company to meet its obligations as they become due for at least one year following the date that the financial statements were available to be issued. As a result, the Company has concluded that management's plans are probable of being achieved to alleviate substantial doubt about the Company's ability to continue as a going concern.

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 original maturity of three months or less to be cash equivalents. As of December 31, 2025 and 2024, 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	
2025	\$	108	\$	414	\$	308	\$	(716)	\$	114
2024	\$	139	\$	448	\$	251	\$	(730)	\$	108

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, premiums, and deferred financing costs are amortized as interest expense on a basis that approximates the effective interest method over the term 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 as of December 31, 2025, we had no outstanding derivatives on the Balance Sheet.

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 2025 and 2024.

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 purchases and normal sales contracts are recognized when the underlying physical transaction is completed under the accrual basis of accounting. From time to time we utilize risk management contracts including interest rate swaps to fix the interest on variable rate debt or to lock in the Treasury yield component associated with anticipated issuance of senior notes. In August 2002, we entered into a treasury lock, which are interest rate swaps, to hedge \$50.0 million of our First Mortgage Bonds due on August 15, 2032. The treasury lock cash settled on August 8, 2002, the bond pricing date, and resulted in a \$1.8 million loss. The treasury lock is designated as a cash flow hedge and the resulting loss is carried in Accumulated other comprehensive loss and is being amortized over the life of the First Mortgage Bonds.

As of December 31, 2025, we had no outstanding derivatives on the Balance Sheet.

Fair Value Measurements

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

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

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

Level 3 - Pricing inputs are generally less observable from objective sources. These inputs reflect management's best estimate of fair value using its own assumptions of 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 hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments.

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

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

Income Taxes

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

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

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

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

We have elected to account for transferable 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.

Pension and Other Postretirement Plans

We recognize on our Balance Sheets an asset or liability reflecting the funded status of pension and other postretirement plans with current-year changes in actuarial gains or losses recognized in regulatory assets or liabilities. All plan assets are recorded at fair value. We follow the measurement date provisions of ASC 715, *Compensation-Retirement Benefits*, which require a year-end measurement date of plan assets and obligations for all defined benefit plans.

Recently Adopted Accounting Standards

Improvements to Income Tax Disclosures, ASU 2023-09

In December 2023, the Financial Accounting Standards Board, FASB, issued ASU 2023-09, *Improvements to Income Tax Disclosures*, which expands entities' annual disclosures by requiring disclosure of tax rate reconciliation amounts and percentages for specific categories, income taxes paid disaggregated by federal and state taxes, and income tax expense disaggregated federal and state taxes jurisdiction. We adopted this ASU retrospectively, effective for our Annual Report for the year ended December 31, 2025. Adoption of this ASU did not have a material impact on our financial statement disclosures. The additional disclosures required by this ASU are included in Note 9.

(2) REGULATORY MATTERS

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

	2025	2024
Regulatory assets		
Deferred energy, fuel and transmission cost adjustments ^(a)	\$ 54,023	\$ 37,722
Deferred taxes on AFUDC ^(b)	4,726	3,812
Employee benefit plans and related deferred taxes ^(b)	17,798	17,802
Deferred taxes on flow through accounting ^(b)	26,862	22,599
Other regulatory assets ^(a)	93	304
Total Other Regulatory Assets (182.3)	<u>\$ 103,502</u>	<u>\$ 82,239</u>
Regulatory liabilities		
Employee benefit plans and related deferred taxes ^(b)	\$ 6,415	\$ 6,559
Excess deferred income taxes ^(b)	83,871	86,181
Other regulatory liabilities ^(b)	471	1,370
Total Other Regulatory Liabilities (254)	<u>\$ 90,757</u>	<u>\$ 94,110</u>

(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 on recovered or amortized as approved by the appropriate state commission. We file periodic quarterly, semi-annual and/or annual filings to recover these costs based on the respective cost mechanisms approved by the applicable state utility commissions.

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

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

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

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

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

Recent Regulatory Activity

FERC Formula Rate

The 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, 2025, the annual revenue requirement was \$32.3 million based on \$190.2 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 and January 2025, we entered into agreements with a third party to sell our 2023 and 2024 generated PTCs, respectively. In January 2026, we entered into a similar agreement with the same third party to sell our 2025 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 and 2025 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.

	2025		Year ended December 31,		2024	
Customer types:						
Retail	\$	243,917	\$	230,532		
Wholesale		11,793		14,200		
Market-off-system sales		27,390		16,469		
Transmission/Other		64,698		66,518		
Revenue from contracts with customers		347,798		327,719		
Other revenues		298		275		
Total Revenues	\$	348,096	\$	327,994		
Timing of revenue recognition:						
Services transferred over time	\$	347,798	\$	327,719		
Revenue from contracts with customers	\$	347,798	\$	327,719		

(5) PROPERTY, PLANT AND EQUIPMENT

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

FERC Accounts	2025	2025 Weighted Average Useful Life (in years)	2024	2024 Weighted Average Useful Life (in years)	Lives (in years)	
					Minimum	Maximum
Electric plant:						
Production	\$ 760,061	45	\$ 731,081	44	25	61
Transmission	301,614	51	299,745	51	42	60
Electric distribution	604,188	45	569,292	45	21	62
Plant acquisition adjustment ^(a)	4,870	N/A	4,870	N/A	N/A	N/A
General	188,285	28	188,412	27	5	40
Operating lease assets	16,643	N/A	16,792	N/A	N/A	N/A
Total plant-in-service	1,875,861		1,810,192			
Construction work-in-progress	101-106,114 107		175,319			
Total electric plant	2,050,980		1,863,100			
Less accumulated depreciation and amortization	(578,246)		(551,839)			
Electric plant net of accumulated depreciation and amortization	\$ 1,472,734		\$ 1,311,261			

(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 6 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 own an undivided ownership interest in Wygen III and are obligated to make payments for costs associated with administrative services and their proportionate share of the costs of operating the plant for the life of the facility. We retain responsibility for plant operations.

Cheyenne Prairie Generating Station

Cheyenne Prairie Generating Station (Cheyenne Prairie), a 140 MW natural-gas fired power generation facility, was placed into commercial operations on October 1, 2014. The facility includes one combined-cycle 100 MW unit that we jointly own with Wyoming Electric, our related party operating in the Cheyenne, Wyoming area. We own 58 MW, and Wyoming Electric owns 42 MW of this combined-cycle unit. Cheyenne Prairie also includes one simple-cycle 40 MW combustion turbine that Wyoming Electric wholly owns. Black Hills Service Company (BHSC) is responsible for plant operations. We are committed to pay our proportionate share of the additions, replacements and operating and maintenance expenses. For the years ended December 31, 2025 and 2024, we were allocated net costs of \$3.5 million and \$3.4 million, respectively, from Wyoming Electric.

Corriedale Wind Farm

Corriedale, a 52.5 MW wind farm near Cheyenne, Wyoming, was placed into commercial operation in November 2020. This wind farm serves as the dedicated wind energy supply to the Renewable Ready program, which is a voluntary renewable energy subscription program for large commercial, industrial and governmental customers in South Dakota and Wyoming. We own 32.5 MW (62%) and Wyoming Electric owns 20 MW (38%) of this wind farm. We are committed to pay our proportionate share of the additions, replacements and operating and maintenance expenses. BHSC is responsible for operations of the wind farm. For the years ended December 31, 2025 and 2024, we allocated net costs of \$0.5 million and \$0.4 million, respectively, to Wyoming Electric.

As of December 31, 2025, 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%	\$ 123,638	\$ -	\$(80,146)	\$ 43,492
Transmission Tie	35%	\$ 24,480	\$ -	\$(8,750)	\$ 15,730
Wygen III	52%	\$ 144,282	\$ 393	\$(31,258)	\$ 113,417
Cheyenne Prairie	58%	\$ 117,158	\$ 12	\$(27,699)	\$ 89,471
Corriedale Wind Farm	62%	\$ 52,548	\$ 123	\$(10,853)	\$ 41,818

(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, 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:

	2025	2024
Return-seeking Assets		
Equity	19%	19%
Real estate	5%	5%
Hedge funds	2%	3%
Fixed income	3%	3%
Total	29%	30%
Liability-hedging Assets		
Fixed income	69%	68%
Cash	2%	2%
Total	71%	70%
Total assets	100%	100%

Supplemental Non-qualified Defined Benefit Plans

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

Non-pension Defined Benefit Postretirement Healthcare Plan

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

Plan Contributions

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

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

	2025		2024	
Defined Contribution Plans				
Company Retirement Contribution	\$	995	\$	965
Matching Contributions	\$	1,458	\$	1,441
Defined Benefit Plans				
Pension Plan	\$	245	\$	305
Healthcare Plan	\$	311	\$	360
Supplemental Plans	\$	292	\$	318

We do not have any required 2026 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, 2025					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV ^(a)	Total Fair Value
Recurring Fair Value Measures						
Common Collective Trust - Cash and Cash Equivalents	\$ -	\$ 856	\$ -	\$ 856	\$ -	\$ 856
Common Collective Trust - Equity	-	7,107	-	7,107	-	7,107
Common Collective Trust - Fixed Income	-	26,884	-	26,884	-	26,884
Common Collective Trust - Real Estate	-	-	-	-	2,020	2,020
Hedge Funds	-	-	-	-	686	686
Total investments measured at fair value	\$ -	\$ 34,846	\$ -	\$ 34,846	\$ 2,706	\$ 37,552
Pension Plan	December 31, 2024					
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV ^(a)	Total Fair Value
Common Collective Trust - Cash and Cash Equivalents	\$ -	\$ 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

(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 funds' 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	
	2025	2024	2025	2024	2025	2024
Service cost	\$ 87	\$ 138	\$ 1	\$ 29	\$ 104	\$ 114
Interest cost	2,154	2,143	87	93	137	147
Expected return on assets	(2,300)	(2,369)	-	-	-	-
Amortization of prior service cost (credits)	(16)	(16)	-	-	-	(26)
Amortization of loss (gain)	-	-	-	-	(5)	-
Recognized net actuarial loss (gain)	476	436	18	20	-	-
Net periodic expense	\$ 401	\$ 332	\$ 106	\$ 142	\$ 236	\$ 235

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	
	2025	2024	2025	2024	2025	2024
Accumulated benefit obligation at December 31,	\$ 42,684	\$ 41,746	\$ 1,716	\$ 1,838	\$ 2,910	\$ 2,783
Change in benefit obligation:						
Benefit obligation at beginning of year	\$ 42,025	\$ 45,638	\$ 1,838	\$ 2,073	\$ 2,783	\$ 3,221
Service cost	87	138	(6)	29	104	114
Interest cost	2,154	2,143	86	93	137	147
Actuarial (gain) loss	1,952	(1,603)	90	(54)	76	(431)
Benefits paid	(3,666)	(4,302)	(292)	(318)	(311)	(350)
Plan participants transfer to affiliate	491	11	-	15	72	(1)
Plan participants' contributions	-	-	-	-	58	93
Benefit obligation at end of year	43,043	42,025	1,716	1,838	2,910	2,783
Change in fair value of plan assets:						
Fair value of plan assets at beginning of year	36,726	40,906	-	-	-	-
Investment income (loss)	3,839	(193)	-	-	-	-
Benefits paid	(3,666)	(4,302)	(292)	(318)	(311)	(360)
Participant contributions	-	-	-	-	58	93
Employer contributions	245	305	292	318	253	267
Plan participants transfer to affiliate	408	10	-	-	-	-
Fair value of plan assets at end of year	37,552	36,726	-	-	-	-
Funded status - deficiency	\$ 5,491	\$ 5,290	\$ 1,716	\$ 1,838	\$ 2,910	\$ 2,783
Amounts recognized on our Balance Sheets as of December 31:						
Other Regulatory Assets (162.3)	\$ 17,316	\$ 17,280	\$ -	\$ -	\$ -	\$ -
Miscellaneous Current and Accrued Liabilities (242)	-	-	256	289	377	397
Accumulated Provision for Pensions and Benefits (228.3)	5,492	5,300	1,422	1,505	2,542	2,386
Other Regulatory Liabilities (254)	-	-	-	-	1,812	1,965
Amounts recognized in AOCI, net of tax as of December 31:						
Net (gain) loss	\$ -	\$ -	\$ 396	\$ 339	\$ -	\$ -
Total amounts included in AOCI, after-tax not yet recognized as components of net periodic expense	\$ -	\$ -	\$ 396	\$ 339	\$ -	\$ -

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

Weighted-average assumptions used to determine benefit obligations:	Pension Plan		Supplemental Plans		Healthcare Plan	
	2025	2024	2025	2024	2025	2024
Discount rate	5.38%	5.63%	5.13%	5.52%	5.32%	5.60%
Rate of increase in compensation levels	3.01%	3.04%	N/A	N/A	N/A	N/A
Weighted-average assumptions used to determine net periodic benefit cost for plan year:						
Discount rate ^(a)	5.63%	4.99%	5.52%	4.91%	5.60%	4.97%
Expected long-term rate of return on assets ^(b)	6.50%	6.00%	N/A	N/A	4.10%	3.50%
Rate of increase in compensation levels	3.04%	3.04%	N/A	N/A	N/A	N/A

(a) The estimated discount rate for the Defined Benefit Pension Plan is 5.38% for the calculation of the 2026 net periodic pension costs.
 (b) The expected rate of return on Defined Benefit Pension Plan assets is 6.50% for the calculation of the 2026 net periodic pension costs.

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

	2025	2024
Trend Rate - Medical		
Pre-65 for next year - All plans	7.00%	7.50%
Pre-65 Ultimate trend rate	4.50%	4.50%
Trend Year	2035	2035
Post-65 for next year - all plans	6.00%	6.50%
Post-65 Ultimate trend rate	4.50%	4.50%
Trend Year	2035	2033

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
2026	\$ 3,665	\$ 256	\$ 377
2027	3,673	224	412
2028	3,637	217	390
2029	3,637	209	350
2030	3,619	202	338
2031-2035	16,987	647	1,260

(9) INCOME TAXES

Transfers of Production Tax Credits

In August 2022, H.R. 5376, commonly known as the IRA of 2022, or IRA, was enacted. 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 and January 2025, under this transferability provision, we entered into agreements with

A third party to sell 2023 generated PTCs for \$3.3 million and 2024 generated PTCs for \$3.6 million. In January 2026, we entered into a similar agreement to sell 2025 generated PTCs for \$3.8 million.

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

One Big Beautiful Bill Act

In July 2025, H.R. 1, commonly referred to as the OBBBA, was enacted. The OBBBA is a legislative package designed to permanently extend certain expiring provisions of the TCJA and deliver additional tax relief for individuals and businesses. The OBBBA introduced changes to federal energy policies by rolling back several clean energy provisions and codified restrictions related to prohibited foreign entities, termination and restrictions on clean energy PTCs, and extension and modification of clean fuel production. The OBBBA does not repeal tax credit transferability provisions enacted under the IRA and continues to permit the execution of our transferability agreements as originally agreed upon, but restricts credit transfers to prohibited foreign entities.

Additionally, on August 15, 2025, the IRS issued Notice 2025-42, which provides guidance on the beginning of construction requirements for applicable wind and solar. These requirements are critical for determining eligibility for energy-related tax credits, particularly considering the OBBBA's modifications to clean energy incentives. Projects must meet specific criteria—such as physical work of a significant nature—to be considered as having begun construction. This determination affects whether a project qualifies under pre-OBBBA or post-OBBBA credit regimes, which may differ in value, availability, or restrictions.

We do not anticipate material impacts to our pre-OBBBA in-service clean energy generation facilities as a result of the OBBBA.

Income Tax Expense

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

	2025	2024
Current income tax expense (Accounts 409.1 and 409.2)	\$ (765)	\$ 1,830
Deferred income tax expense (benefit) (Accounts 410.1 and 411.1)	2,884	3,312
Total income tax expense	<u>\$ 2,119</u>	<u>\$ 5,142</u>

Effective Tax Rates

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

	2025		2024	
	(dollars in thousands)			
	\$	%	\$	%
Income before income taxes	56,793		63,807	
U.S. Federal statutory rate	11,927	21.0%	13,400	21.0%
State and local income taxes, net of federal income tax effect ^(a)	90	0.2%	131	0.2%
Tax credits				
Energy-related tax credits, net of transferability discount	(3,803)	(6.7)%	(3,370)	(5.3)%
Other	(421)	(0.7)%	(513)	(0.8)%
Nontaxable or Nondeductible Items				
Other	41	0.1%	29	0.1%
Changes in Unrecognized Tax Benefits				
Regulatory	125	0.2%	291	0.5%
Amortization of excess deferred income taxes ^(b)	(1,853)	(3.3)%	(1,793)	(2.8)%
Flow-through adjustments	(2,704)	(4.8)%	(2,229)	(3.5)%
Other	(721)	(1.3)%	145	0.2%
Other	(562)	(1.0)%	(949)	(1.5)%
Effective tax rate	<u>\$ 2,119</u>	<u>3.7%</u>	<u>\$ 5,142</u>	<u>8.1%</u>

(a) State taxes in Montana made up the majority (greater than 50%) of the tax effect.
(b) Primarily impacted by the Tax Cuts and Jobs Act (TCJA).

Income Taxes Paid

Income taxes (paid) received at December 31 were as follows (in thousands):

	2025		2024	
Federal:				
Direct payments (net of refunds)	\$ -		\$ (2,456)	
Transferred Renewable Credits (net of discount)	3,585		3,374	
Total Federal	<u>\$ 3,585</u>		<u>\$ 918</u>	
State:				
Colorado ^(a)	(1)		N/A	
Nebraska ^(a)	(2)		N/A	
Montana ^(a)	(87)		N/A	
Other	-		(131)	
Total State	<u>\$ (90)</u>		<u>\$ (131)</u>	
Total income taxes (paid) received	<u>\$ 3,495</u>		<u>\$ 787</u>	

(a) N/A indicates the amount of income taxes paid during the year does not meet the 5% disaggregation threshold.

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 paid are payments to or from BHC and represent amounts we would incur as a separate C-corporation.

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):

	2025		2024	
Deferred tax assets:				
Regulatory liabilities	\$ 21,735		\$ 22,170	
Employee benefit plans	1,711		1,657	
Accumulated depreciation and other plant-related differences	2,273		2,079	
Credit carryovers	16,198		15,763	
Federal NOL	-		-	
Other	3,784		4,387	
Total deferred tax assets (Account 190)	<u>45,701</u>		<u>46,056</u>	
Deferred tax liabilities:				
Regulatory assets	(9,832)		(8,643)	
Accelerated depreciation and other plant related differences	(167,106)		(161,817)	
Employee benefit plans	(2,965)		(3,048)	
Deferred energy costs	(11,434)		(7,770)	
Other	(2,865)		(2,950)	
Total deferred tax liabilities (Accounts 282 and 283)	<u>(194,202)</u>		<u>(184,238)</u>	
Net deferred tax assets (liabilities)	<u>\$ (148,501)</u>		<u>\$ (138,182)</u>	

Net Operating Loss and Tax Credit Carryforwards

At December 31, 2025, 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	\$ 16,198	2030-2045

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):

	2025		2024	
Unrecognized tax benefits at January 1	\$ 1,382		\$ 1,091	
Additions for prior year tax positions	-		150	
Additions for current year tax positions	137		153	
Reductions for prior year tax positions	(12)		(12)	
Unrecognized tax benefits at December 31	<u>\$ 1,507</u>		<u>\$ 1,382</u>	

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately \$1.5 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, 2025, and 2024, 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, 2026.

(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 four years to 24 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, 2025, and 2024, were not material to the financial statements.

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

	Balance Sheet Location		As of December 31, 2025		As of December 31, 2024	
Assets:						
Operating leases	Utility Plant (101-106,114)	\$ 16,643	\$ 16,792			
Capital leases	Utility Plant (101-106,114)	151	-			
Operating leases	(Less) Accum. Prov. For Depr. Amort. Depl. (108, 110, 111, 115)	(3,932)	(3,588)			
Total lease assets		<u>\$ 12,862</u>	<u>\$ 13,204</u>			
Liabilities:						
Operating leases	Obligations Under Capital Leases - Noncurrent (227)	\$ 12,495	\$ 12,854			
Operating leases	Obligations Under Capital Leases - Current (243)	353	358			
Total lease liabilities		<u>\$ 12,848</u>	<u>\$ 13,212</u>			

As of December 31, 2025, scheduled maturities of operating lease liabilities for future years were as follows (in thousands):

	Total
2026	\$ 933
2027	933
2028	933
2029	932
2030	857
Thereafter	16,091
Total lease payments	<u>\$ 20,679</u>
Less imputed interest	<u>(7,832)</u>

(11) RELATED-PARTY TRANSACTIONS

Dividends (to) from Parent

For the year ended December 31, 2025, we received net dividends of \$5.0 million from our Parent. For the year ended December 31, 2024, we paid net dividends of \$42.5 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 4.81% at December 31, 2025.

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

	2025	2024
Money pool interest receivable - Notes Receivable from Associated Companies (145)	\$ -	\$ 12
Money pool notes payable - Notes Payable to Associated Companies (233)	40,740	3,987
Money pool interest payable - Notes Payable to Associated Companies (233)	104	-

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

	2025	2024
Money pool interest income (Account 419)	\$ 557	\$ 1,045
Money pool interest expense (Account 430)	973	620

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):

	2025	2024
Long-term Notes payable to Parent - Notes Payable to Associated Companies (223)	\$ 248,450	\$ 196,450
Interest payable on borrowings from associated companies (233)	958	755

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

	2025	2024
Notes payable to Parent interest expense - Interest on Debt to Assoc. Companies (430)	\$ 9,962	\$ 6,653

Interest Expense Allocation from Parent

BHC provides daily liquidity and cash management on behalf of all its subsidiaries. For the years ended December 31, 2025, and 2024, we were allocated \$3.3 million and \$4.4 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 years ended December 31, 2025, and 2024, we received \$3.5 million and \$0.7 million of net proceeds, respectively, from BHC due to our tax sharing agreement.

As of December 31, 2025, we had a \$5.3 million income tax payable to BHC related to our tax sharing agreement. As of December 31, 2024, we had a \$2.6 million income tax 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, 2025, and 2024, South Dakota Electric allocated net costs of \$4.5 million and \$4.6 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):

	2025	2024
Operating Revenues:		
Excess energy sold to Wyoming Electric	\$ 74	\$ 11
Rent revenue from affiliates under Gillette energy complex shared facilities agreement	3,365	3,248
Rent revenue from BHSC under Horizon Point shared facilities agreement	9,326	11,435
Spare turbine agreements with Black Hills Colorado IPP and Wyoming Electric	4,134	2,926
Operating Expenses:		
Purchases from WRDC	\$ 15,913	\$ 18,829
Purchases of excess energy from Wyoming Electric	66	28
Purchase of renewable wind energy from Wyoming Electric - Happy Jack	1,635	1,475
Purchase of renewable wind energy from Wyoming Electric - Silver Sage	3,653	3,554
Gas transportation service agreement with Wyoming Gas	214	239
Rent expense to affiliates under Gillette energy complex shared facility agreement	370	396
Wygen III ground lease with WRDC	1,232	1,200
Spare turbine agreements with Black Hills Colorado IPP and Wyoming Electric	740	764
Direct services and fees from BHSC	14,995	10,977
Indirect services and fees from BHSC	46,931	45,011

(12) SUPPLEMENTAL CASH FLOW INFORMATION

	2025	2024
Years ended December 31, (in thousands)		
Cash (paid) refunded during the period for:		
Interest (net of amounts capitalized)	\$ (31,100)	\$ (32,609)
Income taxes, net of transferred tax credits	3,495	787
Non-cash investing and financing activities:		
Accrued property, plant and equipment purchases at December 31	\$ 33,743	\$ 9,723

(13) LONG-TERM DEBT

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

	Due Date	Interest Rate at December 31, 2025	December 31, 2025	December 31, 2024
First Mortgage bonds due 2032	August 15, 2032	7.23%	\$ 75,000	\$ 75,000
First Mortgage bonds due 2039	November 1, 2039	6.13%	180,000	180,000
First Mortgage bonds due 2044	October 20, 2044	4.43%	85,000	85,000
Total Bonds (221)			\$ 340,000	\$ 340,000
Unamortized Debt Expenses (181)			1,719	1,852
Unamortized Discount on Long-Term Debt (226)			57	61

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):

	2026	2027	2028	2029	2030	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, 2025.

(14) PENDING MERGER BETWEEN BHC AND NORTHWESTERN ENERGY

On August 18, 2025, BHC entered into an agreement and plan of merger, with NorthWestern Energy Group, Inc. ("NorthWestern") and River Merger Sub Inc. ("Merger Sub"). The merger agreement provides for Merger Sub to merge with and into NorthWestern, with NorthWestern continuing as the surviving entity and a direct wholly owned subsidiary of BHC, which will assume a new corporate name as the resulting parent company of the combined corporate group. At the effective time of the Merger (the "Effective Time"), each share of common stock of NorthWestern, par value \$0.01 per share, issued and outstanding as of immediately prior to the Effective Time will be converted into the right to receive 0.98 validly issued, fully paid and non-assessable shares of our common stock, par value \$1.00 per share (or cash-in-lieu of fractional shares thereof), in each case upon and subject to the terms and conditions of the merger agreement.

The merger agreement, which was unanimously approved by both the board of directors of BHC and the board of directors of NorthWestern on August 18, 2025, provides for a tax-free, all-stock business combination of BHC and NorthWestern upon the terms and subject to the conditions set forth therein. Such conditions include, among other things, clearance under the Hart-Scott-Rodino Act, consent of the Federal Communications Commission, approval from each company's shareholders, and regulatory approvals, including approval from the South Dakota Public Utilities Commission, Nebraska Public Service Commission and Montana Public Service Commission, as well as the United States Department of Energy's Federal Energy Regulatory Commission.

At closing, the combined company will be named Bright Horizon Energy Corporation.

We anticipate the transaction closing in the second half of 2026, subject to the satisfaction of certain closing conditions including receipt of shareholder approvals and certain regulatory approvals as mentioned above.

Name of Respondent:
Black Hills Power Inc.

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

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year		(397,249)			(364,225)		(761,474)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income		14,530			50,822		65,352		
3	Preceding Quarter/Year to Date Changes in Fair Value		43,527					43,527		
4	Total (lines 2 and 3)		58,057			50,822		108,879	58,398,395	58,507,274
5	Balance of Account 219 at End of Preceding Quarter/Year		(339,192)			(313,403)		(652,595)		
6	Balance of Account 219 at Beginning of Current Year		(339,192)			(313,403)		(652,595)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income		14,026			50,822		64,848		
8	Current Quarter/Year to Date Changes in Fair Value		(70,775)					(70,775)		
9	Total (lines 7 and 8)		(56,749)			50,822		(5,927)	54,685,021	54,679,094
10	Balance of Account 219 at End of Current Quarter/Year		(395,941)			(262,581)		(658,522)		

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)	1,787,916,739	1,750,044,593		37,872,146			
4	Property Under Capital Leases	16,793,340	16,793,340					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	59,842,731	59,842,731					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	1,864,552,810	1,826,680,664		37,872,146			
9	Leased to Others							
10	Held for Future Use	6,238,342	6,238,342					
11	Construction Work in Progress	175,318,530	175,318,530					
12	Acquisition Adjustments	4,870,309	4,870,309					
13	Total Utility Plant (8 thru 12)	2,050,979,991	2,013,107,845		37,872,146			
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	578,246,183	564,469,609		13,776,574			
15	Net Utility Plant (13 less 14)	1,472,733,808	1,448,638,236		24,095,572			
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	569,907,738	556,131,164		13,776,574			
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							
22	Total in Service (18 thru 21)	569,907,738	556,131,164		13,776,574			
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion	3,942,206	3,942,206					
26	Total Leased to Others (24 & 25)	3,942,206	3,942,206					
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	4,396,239	4,396,239					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	578,246,183	564,469,609		13,776,574			

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: 12/31/2025	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases

Amount represents capital and operating leases.

(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	SUBTOTAL (Total 2 thru 5)					
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL (Total 8 & 9)					
11	Spent Nuclear Fuel (120.4)					
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)					
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)					
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

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		82,754				82,754
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)		82,754				82,754
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	230,796				(4,205)	226,591
9	(311) Structures and Improvements	56,326,514	568,503	85,450		(160,235)	56,649,332
10	(312) Boiler Plant Equipment	261,627,623	20,729,537	744,084		(582,245)	281,030,831
11	(313) Engines and Engine-Driven Generators	598,824					598,824
12	(314) Turbogenerator Units	124,615,797	9,757,877	4,651,310		(1,528,966)	128,193,398
13	(315) Accessory Electric Equipment	20,641,282	511,713	3,136		(38,722)	21,111,137
13.1	(315.1) Computer Hardware		1,063,934	628,215		1,872,606	2,308,325
13.2	(315.2) Computer Software					277,450	277,450
13.3	(315.3) Communication Equipment		351,039			706,913	1,057,952
14	(316) Misc. Power Plant Equipment	3,484,369	437,993			(221,448)	3,700,914
15	(317) Asset Retirement Costs for Steam Production						
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	467,525,205	33,420,596	6,112,195		321,148	495,154,754
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						
19	(321) Structures and Improvements						
20	(322) Reactor Plant Equipment						
21	(323) Turbogenerator Units						
22	(324) Accessory Electric Equipment						
22.1	(324.1) Computer Hardware						
22.2	(324.2) Computer Software						
22.3	(324.3) Communication Equipment						
23	(325) Misc. Power Plant Equipment						
24	(326) Asset Retirement Costs for Nuclear Production						
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)						
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights						
28	(331) Structures and Improvements						
29	(332) Reservoirs, Dams, and Waterways						
30	(333) Water Wheels, Turbines, and Generators						
31	(334) Accessory Electric Equipment						
31.1	(334.1) Computer Hardware						
31.2	(334.2) Computer Software						
31.3	(334.3) Communication Equipment						
32	(335) Misc. Power Plant Equipment						
33	(336) Roads, Railroads, and Bridges						
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)						

35.1	D. Solar Production Plant						
35.2	(338.1) Land and Land Rights						
35.3	(338.2) Structures and Improvements						
35.5	(338.4) Solar Panels						
35.6	(338.5) Collector System						
35.7	(338.6) Generator Step-up Transformers (GSU)						
35.8	(338.7) Inverters						
35.9	(338.8) Other Accessory Electrical Equipment						
35.10	(338.9) Computer Hardware						
35.11	(338.10) Computer Software						
35.12	(338.11) Communication Equipment						
35.13	(338.12) Miscellaneous Power Plant Equipment						
35.14	(338.13) Asset Retirement Costs for Solar Production						
35.15	TOTAL Solar Production Plant (Enter Total of lines 35.2 thru 35.14)						
35.16	E. Wind Production Plant						
35.17	(338.20) Land and Land Rights						
35.18	(338.21) Structures and Improvements					3,408,309	3,408,309
35.20	(338.23) Wind Turbines		(279,940)			29,507,685	29,227,745
35.21	(338.24) Wind Towers and Fixtures					12,779,716	12,779,716
35.23	(338.26) Collector System					3,192,515	3,192,515
35.24	(338.27) Generator Step-up Transformers (GSU)						
35.25	(338.28) Inverters						
35.26	(338.29) Other Accessory Electrical Equipment						
35.27	(338.30) Computer Hardware						
35.28	(338.31) Computer Software						
35.29	(338.32) Communication Equipment					33,402	33,402
35.30	(338.33) Miscellaneous Power Plant Equipment						
35.31	(338.34) Asset Retirement Costs for Wind Production					756,044	756,044
35.32	TOTAL Wind Production Plant (Enter Total of lines 35.17 thru 35.31)		(279,940)			49,677,671	49,397,731
35.33	F. Other Renewable Production Plant						
35.34	(339.1) Land and Land Rights						
35.35	(339.2) Structures and Improvements						
35.36	(339.3) Fuel Holders						
35.37	(339.4) Boilers						
35.39	(339.6) Generators						
35.41	(339.8) Other Accessory Electrical Equipment						
35.42	(339.9) Computer Hardware						
35.43	(339.10) Computer Software						
35.44	(339.11) Communication Equipment						
35.45	(339.12) Miscellaneous Power Plant Equipment						
35.46	(339.13) Asset Retirement Costs for Other Renewable Production						
35.47	TOTAL Other Renewable Production Plant (Enter Total of lines 35.34 thru 35.46)						
36	G. Other Production Plant						
37	(340) Land and Land Rights	1,879,679			106,445		1,773,234
38	(341) Structures and Improvements	11,712,789	348,869		4,725	(3,408,309)	8,648,624
39	(342) Fuel Holders, Products, and Accessories	6,531,456	(388)				6,531,068
40	(343) Prime Movers						
41	(344) Generators	214,943,675	4,625,758		1,097,171	(45,638,678)	172,833,584
42	(345) Accessory Electric Equipment	22,214,812	171,394		80,921	(3,151,417)	19,153,868
42.1	(345.1) Computer Hardware		245,526		916,702	946,988	275,812
42.2	(345.2) Computer Software					373,834	373,834
42.3	(345.3) Communication Equipment					54,297	54,297
43	(346) Misc. Power Plant Equipment	353,187				(3,855)	349,332
44	(347) Asset Retirement Costs for Other Production	756,044				(756,044)	0
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	258,391,642	5,391,159		2,205,964	(51,583,184)	209,993,653
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, 35.15, 35.32, 35.47, and 45)	725,916,847	38,531,815		8,318,159	(1,584,365)	754,546,138
47	3. Transmission Plant						

48	(350) Land and Land Rights	10,337,075	25					10,337,100
48.2	(351.1) Computer Hardware							
48.3	(351.2) Computer Software							
48.4	(351.3) Communication Equipment		1,762,016				1,842,859	3,604,875
49	(352) Structures and Improvements	2,021,051						2,021,051
50	(353) Station Equipment	76,322,137	385,438		319,504		(3,162,970)	73,225,101
51	(354) Towers and Fixtures	1,016,048					(151,222)	864,826
52	(355) Poles and Fixtures	116,110,310	(34,718)		80,251		189,870	116,185,211
53	(356) Overhead Conductors and Devices	93,599,364	172,236		5,894		(26,802)	93,738,904
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)	299,412,905	2,284,997		405,649		(1,308,265)	299,983,988
59	4. Distribution Plant							
60	(360) Land and Land Rights	3,210,857	399,893		992			3,609,758
61	(361) Structures and Improvements	2,331,121			4,848			2,326,273
62	(362) Station Equipment	115,908,728	5,808,701		361,809		(2,673,154)	118,682,466
63.1	(363.1) Computer Hardware							
63.2	(363.2) Computer Software							
63.3	(363.3) Communication Equipment		1,717,340		1,745		2,477,095	4,192,690
64	(364) Poles, Towers, and Fixtures	124,736,652	6,440,157		474,615	(163,505)	270,235	130,808,924
65	(365) Overhead Conductors and Devices	71,200,529	1,169,760		156,536		(127,572)	72,086,181
66	(366) Underground Conduit	25,101,322	3,192,260		57,284	(69,499)	4,645	28,171,444
67	(367) Underground Conductors and Devices	88,930,213	6,717,062		265,237	(114,793)	83,678	95,350,923
68	(368) Line Transformers	71,951,694	9,121,911		1,294,607	(65,353)	739,759	80,453,404
69	(369) Services	42,673,386	1,894,502		26,005	(85,981)	(37,968)	44,417,934
70	(370) Meters	12,558,760	527,586		219,639		709,068	13,575,775
71	(371) Installations on Customer Premises	3,346,553	129,542		3,428		(3,441)	3,469,226
72	(372) Leased Property on Customer Premises							
73	(373) Street Lighting and Signal Systems	3,228,379	763,222		342,658		(432,307)	3,216,636
74	(374) Asset Retirement Costs for Distribution Plant							
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	565,178,194	37,881,936		3,209,403	(499,131)	1,010,038	600,361,634
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT							
77	(380) Land and Land Rights							
78	(381) Structures and Improvements							
79	(382) Computer Hardware							
80	(383) Computer Software							
81	(384) Communication Equipment							
82	(385) Miscellaneous Regional Transmission and Market Operation Plant							
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper							
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)							
84.1	6. ENERGY STORAGE PLANT							
84.2	(387.1) Land and Land Rights							
84.3	(387.2) Structures and Improvements							
84.4	(387.3) Energy Storage Equipment							
84.6	(387.5) Collector System							
84.7	(387.6) Generator Step-up Transformers (GSU)							
84.8	(387.7) Inverters							
84.9	(387.8) Computer Hardware							
84.10	(387.9) Computer Software							
84.11	(387.10) Communication Equipment							
84.12	(387.11) Miscellaneous Energy Storage Equipment							
84.13	(387.12) Asset Retirement Costs for Energy Storage							
84.14	TOTAL Energy Storage Plant (Total lines 84.2 thru 84.13)							
85	7. General Plant							
86	(389) Land and Land Rights	5,155,021	1					5,155,022

87	(390) Structures and Improvements	86,583,069	315,368	134,452		191,394	86,955,379
88	(391) Office Furniture and Equipment	14,952,053	1,433,492	64,895		(5,957,234)	10,363,416
89	(392) Transportation Equipment	30,423,545	2,078,390	2,088,512			30,413,423
90	(393) Stores Equipment	220,732	163,951				384,683
91	(394) Tools, Shop and Garage Equipment	4,007,757	188,385	41,930		(190,598)	3,963,614
92	(395) Laboratory Equipment	742,500	77,047				819,547
93	(396) Power Operated Equipment	4,131,651	16,760			190,598	4,339,009
94	(397.1) Computer Hardware		1,332,245	114,964		2,421,761	3,639,042
94.1	(397.2) Computer Software						
94.2	(397.3) Communication Equipment	6,753,339	1,292,210	412,667		(472,656)	7,160,226
95	(398) Miscellaneous Equipment	1,524,053	173,669			21,726	1,719,448
96	SUBTOTAL (Enter Total of lines 86 thru 95)	154,493,720	7,071,518	2,857,420		(3,795,009)	154,912,809
97	(399) Other Tangible Property	16,792,412	929				16,793,341
98	(399.1) Asset Retirement Costs for General Plant						
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	171,286,132	7,072,447	2,857,420		(3,795,009)	171,706,150
100	TOTAL (Accounts 101 and 106)	1,761,794,078	85,853,949	14,790,631	(499,131)	(5,677,601)	1,826,680,664
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)	1,761,794,078	85,853,949	14,790,631	(499,131)	(5,677,601)	1,826,680,664

Name of Respondent:
Black Hills Power Inc.

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

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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)
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44						
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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		44,156
3	Kirk Station - Land	11/30/2022		7,015
4	Neil Simpson Station I - Land	10/01/2014		1,000
5	Osage Plant - Land	10/01/2014		179,368
6	St. Onge 230kV Substation - Land	07/01/2017		254,256
7	Catron Blvd. Rapid City Campus - Land	01/31/2023		887,365
8	Lange II - Land	05/01/2024		4,049,221
9				
21	Other Property:			
22	Osage Plant - Water/Well Assets	10/01/2014		815,961
47	TOTAL			6,238,342

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	10086233-West Hill Subdivision Rebuild	1,832,471
2	10086234-Sundance Hill Distribution XFMR Rep	1,793,522
3	60260612-BHE RC SD-Fire Mitigation Meade County	1,715,833
4	10086222-4th Street Sub Engineering	1,559,010
5	60246965-BHE-2 Other/Weather St, Custer	1,186,842
6	60252745-BHE RC SD-Downtown 2025-Rapid City	1,157,246
7	DISTRIBUTION PLANT LESS THAN \$1,000,000 EACH	6,935,680
8	10088699-California Independent System Operator (CAISO) Western Energy Imbalance Market (WEIM)	1,211,720
9	GENERAL PLANT-ELECTRIC LESS THAN \$1,000,000 EACH	1,699,051
10	10084596-CT1 Major OH & Conversion	4,536,220
11	10088541-Lange CT PD to PF Conversion	3,103,820
12	10091478-Lange Natural Gas Interconnect Upgrade	1,491,743
13	OTHER GENERATION -PLANT LESS THAN \$1,000,000 EACH	667,122
14	10085466-Lange II	142,573,962
15	10091817-NS2 Hydrojets	1,027,227
16	STEAM GENERATION LESS THAN \$1,000,000 EACH	2,321,018
17	TRANSMISSION LESS THAN \$1,000,000 EACH	506,043
43	Total	175,318,530

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

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

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
Section A. Balances and Changes During Year					
1	Balance Beginning of Year	535,504,700	535,504,700		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	47,258,469	47,258,469		
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	1,054,604	1,054,604		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Right of Use	3,932,385	3,932,385		
9.2	Capital Lease	9,821	9,821		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	52,286,906	52,286,906		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(14,298,717)	(14,298,717)		
13	Cost of Removal	(2,399,415)	(2,399,415)		
14	Salvage (Credit)	1,749,380	1,749,380		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(14,948,752)	(14,948,752)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Asset Retirement Obligation and Pending Retirements	(12,769,484)	(12,769,484)		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	560,073,370	560,073,370		
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	185,873,722	185,873,722		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
23.1	Solar Production				
23.2	Wind Production	9,825,608	9,825,608		
23.3	Other Renewable Production				
24	Other Production	76,953,830	76,953,830		
25	Transmission	55,322,248	55,322,248		
26	Distribution	193,687,355	193,687,355		
27	Regional Transmission and Market Operation				
27.1	Energy Storage				
28	General	38,410,607	38,410,607		
29	TOTAL (Enter Total of lines 20 thru 28)	560,073,370	560,073,370		

(a) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

Amounts footnoted are based upon FERC-approved rates

Note: Amounts footnoted are based upon FERC-approved rates					
Line #	Item (a)	Total (+ d + e)	Electric Plant in Service (c)	Held for Future Use (d)	Leased To Others (e)
Section A. Balances and Changes During Year					
1	Balance Beginning of Year	567,758,290	567,758,290		
2. Depreciation Provisions for Year, Charged to					
3	(403) Depreciation Expense	49,232,608	49,232,608		
4	(403.1) Depreciation Expense for Asset Retirement Costs	31,627	31,627		
5	(413) Exp. of Elec. Pl. Leas. to Others	-	-		
6	Transportation Expenses-Clearing	2,837,252	2,837,252		
7	Other Clearing Accounts	-	-		
8	Other Accounts (Specify, details in footnote)	3,332,395	3,332,395		
9		-	-		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	56,033,872	56,033,872	-	-
11 Net Charges for Plant Retired:					
12	Book Cost of Plant Retired	(14,238,717)	(14,238,717)		
13	Cost of Removal	(2,339,416)	(2,339,416)		
14	Salvage (Credit)	1,743,380	1,743,380		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(14,948,753)	(14,948,753)	-	-
16	Other Debit or Cr. Items (Describe, details in footnote)	(12,769,484)	(12,769,484)		
17.1	Transfers	-	-		
18	Book Cost or Asset Retirement Costs Retired	-	-		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	536,073,325	536,073,325	-	-
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	185,873,722	185,873,722		
21	Nuclear Production	-	-		
22	Hydraulic Production-Conventional	-	-		
23	Hydraulic Production-Pumped Storage	-	-		
25	Solar Production	-	-		
26	Wind Production	9,825,607	9,825,607		
27	Other Renewable Production	-	-		
28	Other Production	76,353,830	76,353,830		
29	Transmission	55,373,421	55,373,421		
30	Distribution	193,687,355	193,687,355		
31	Regional Transmission and Market Operation	-	-		
32	Energy Storage Plans	-	-		
33	General	74,359,390	74,359,390		
34	TOTAL (Enter Total of lines 20 thru 28)	536,073,325	536,073,325	-	-

(b) Concept: AccumulatedDepreciationOtherProduction

Amount includes an asset retirement obligation of \$128,777

(c) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

Amounts footnoted are based upon FERC-approved rates

Note: Amounts footnoted are based upon FERC-approved rates					
Line #	Item (a)	Total (+ d + e)	Electric Plant in Service (c)	Held for Future Use (d)	Leased To Others (e)
Section A. Balances and Changes During Year					
1	Balance Beginning of Year	567,758,290	567,758,290		
2. Depreciation Provisions for Year, Charged to					
3	(403) Depreciation Expense	49,232,608	49,232,608		
4	(403.1) Depreciation Expense for Asset Retirement Costs	31,627	31,627		
5	(413) Exp. of Elec. Pl. Leas. to Others	-	-		
6	Transportation Expenses-Clearing	2,837,252	2,837,252		
7	Other Clearing Accounts	-	-		
8	Other Accounts (Specify, details in footnote)	3,332,395	3,332,395		
9		-	-		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	56,033,872	56,033,872	-	-
11 Net Charges for Plant Retired:					
12	Book Cost of Plant Retired	(14,238,717)	(14,238,717)		
13	Cost of Removal	(2,339,416)	(2,339,416)		
14	Salvage (Credit)	1,743,380	1,743,380		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(14,948,753)	(14,948,753)	-	-
16	Other Debit or Cr. Items (Describe, details in footnote)	(12,769,484)	(12,769,484)		
17.1	Transfers	-	-		
18	Book Cost or Asset Retirement Costs Retired	-	-		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	536,073,325	536,073,325	-	-
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	185,873,722	185,873,722		
21	Nuclear Production	-	-		
22	Hydraulic Production-Conventional	-	-		
23	Hydraulic Production-Pumped Storage	-	-		
25	Solar Production	-	-		
26	Wind Production	9,825,607	9,825,607		
27	Other Renewable Production	-	-		
28	Other Production	76,353,830	76,353,830		
29	Transmission	55,373,421	55,373,421		
30	Distribution	193,687,355	193,687,355		
31	Regional Transmission and Market Operation	-	-		
32	Energy Storage Plans	-	-		
33	General	74,359,390	74,359,390		
34	TOTAL (Enter Total of lines 20 thru 28)	536,073,325	536,073,325	-	-

Name of Respondent:
Black Hills Power Inc.

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

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1								
2								
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36								
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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)	7,095,782	5,958,241	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)	8,883,548	8,628,093	Transmission & Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	23,976,781	25,893,761	Production
8	Transmission Plant (Estimated)	151,544	149,337	Transmission
9	Distribution Plant (Estimated)	748,995	725,881	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
10.1	Energy Storage Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	272,561	264,148	General
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	34,033,429	35,661,220	
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)	3,454,259	2,376,838	
17				
20	TOTAL Materials and Supplies	44,583,470	43,996,299	

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: 12/31/2025	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesOther

This amount represents allocated O&M capitalized to General material and supplies.

Name of Respondent:
Black Hills Power Inc.

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

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

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

Name of Respondent:
Black Hills Power Inc.

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

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR		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					

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
2	Plan Study Joint Transmission 230kV	21,382	561.2	4,907	561.2
3	Plan Study Joint Transmission 230kV	365	561.5		
4	Basin Electric NITS-500	24,649	561.6	24,649	561.6
5	Basin Electric NITS-275	4,235	561.6	4,292	561.6
20	Total	50,631		33,848	
21	Generation Studies				
39	Total				
40	Grand Total	50,631		33,848	

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	30,913,379	172,903,736	Various	156,981,800	46,835,315
2	Transmission Cost Adjustment	6,788,024	31,354,323	Various	30,954,935	7,187,412
3	Deferred Taxes on AFUDC	3,812,287	930,200	Various	16,262	4,726,225
4	Deferred Taxes on Flow Through Accounting	22,598,539	4,327,800	190.3	65,459	26,860,880
5	Deferred Taxes related to Retiree Healthcare Plan - Regulatory Liability	522,400		Various	40,638	481,762
6	Pension Plan	17,279,769	512,550	Various	476,440	17,315,879
7	^(b) Energy Efficiency	298,615	58	Various	298,673	0
8	^(b) Carbon Capture Compliance Surcharge	5,323	4,951	Various	10,274	0
9	Western Energy Imbalance Market (WEIM) Implementation Costs	20,212	129,919	Various	55,571	94,560
44	TOTAL	82,238,548	210,163,537		188,900,052	103,502,033

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: 12/31/2025	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Black Hills Power has WPSC 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	4,395,885	221,781	131	442,819	4,174,847
2	Corriedale Spare Parts Consigned Inventory	105,695		548	1,957	103,738
3	Integrated Resource Plan	235,729				235,729
4	Carbon Capture	(80,529)				(80,529)
5	Other Miscellaneous Deferred Debits	859,011	129,271	Various	25,445	962,837
6	Captive Insurance Contribution		600,000	234	300,000	300,000
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	5,515,791				5,696,622

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		
3	Bad Debt Reserve		
4	Bonus Compensation		
5	Credit Carryovers	15,763,131	16,198,219
6	Deferred Compensation		
7	Defined Benefit Pension Plan		
8	Defined Benefit Pension Plan AOCI		
9	Depreciation	2,079,133	2,272,462
10	Employee Benefit Plans	1,656,940	1,710,734
11	Line Extension Deposits		
12	Net Operating Loss Carryforward		
13	Non-qualified Pension Plan		
14	Operating Leases		
15	Production Tax Credits		
16	Regulatory Assets	22,169,960	21,734,864
17	Retiree Healthcare Plan		
7	Other	4,386,775	3,784,759
8	TOTAL Electric (Enter Total of lines 2 thru 7)	46,055,939	45,701,038
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)	46,055,939	45,701,038

Notes

Name of Respondent:
Black Hills Power Inc.

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(2) A Resubmission

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

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	Credit Carryovers	\$ 15,763,131	\$ 16,198,219
3	Depreciation	\$ 2,079,133	\$ 2,272,462
4	Employee benefit plans	\$ 1,656,940	\$ 1,710,734
5	Net Operating Loss Carryforward		\$ -
6	Regulatory Assets	\$ 21,059,500	\$ 21,141,005
7	Other	\$ 4,386,775	\$ 3,784,760
8			
9	TOTAL Electric (Enter Total of lines 2 thru 7)	\$ 44,945,479	\$ 45,107,178
10	Gas		
11			
12	Other		
13	TOTAL Gas (Enter Total of lines 10 thru 15)		
14			
15	Other (Specify)		
16	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	\$ 44,945,479	\$ 45,107,178

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	Donations Received from Stockholders (Account 208)	
2	Beginning Balance Amount	
3	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	Reduction in Par or Stated Value of Capital Stock (Account 209)	
6	Beginning Balance Amount	
7	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)	
10	Beginning Balance Amount	
11	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	Miscellaneous Paid-In Capital (Account 211)	
14	Beginning Balance Amount	
15.1	Capitalization Adjustment	15,000,000
15	Increases (Decreases) Due to Miscellaneous Paid-In Capital	15,000,000
16	Ending Balance Amount	15,000,000
17	Other Paid in Capital	
18	Beginning Balance Amount	
19	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	15,000,000

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: 12/31/2025	Year/Period of Report End of: 2025/ 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

Name of Respondent:
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12/31/2025

Year/Period of Report
End of: 2025/ Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2	2002 AE Bonds, 7.23%	Various	75,000,000		991,063			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		3,985,335		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, 4.63%	Various	248,450,000					12/01/2025	12/31/2029			248,450,000	9,962,079
13	Subtotal		248,450,000									248,450,000	9,962,079
14	Other Long Term Debt (Account 224)												
15													
18	Subtotal												
33	TOTAL		588,450,000									588,450,000	30,175,079

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FOOTNOTE DATA

(a) Concept: InterestExpenseDebtAdvancesFromAssociatedCompanies

\$ 973,480	Utility Money Pool interest expense
\$ 9,962,077	Long-term Notes payable to Parent interest expense
\$ 2,986,553	BHC/Parent daily liquidity and cash management interest expense
\$ 13,922,110	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)	54,685,021
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	2,118,790
11	Benefits Addback	1,641,606
12	Other Comprehensive Income	64,332
13	Operating Lease Asset	493,405
14	Straight Line Lease Asset	1,958
15	Public Utilities Commission Fees	177,647
16	Fines & Penalties	59,574
17	Asset Retirement Obligation FASB 143 Asset	58,342
18	Club Dues	56,670
19	Lobbying	38,711
20	Entertainment	9,815
21	Prepaid Expense	21,200
22	Meals	133,492
23	Line Extension Deposit	123,746
24	Deferred Compensation	31,780
25	Benefits Deduction	(297,559)
14	Income Recorded on Books Not Included in Return	
15	Operating Lease Liability	(538,899)
16	Insurance Reserve	(1,750,000)
17	Finance Lease (netted value)	(2,406)
18	Bad Debt Reserve	(235,309)
19	Depreciation	(29,410,726)
20	Officer Supplemental Life Insurance	(101,274)
21	Deferred Regulatory Asset	(18,693,456)
19	Deductions on Return Not Charged Against Book Income	
20		
27	Federal Tax Net Income	8,686,460
28	Show Computation of Tax:	
29	Tax Amount	1,824,157
30	Tax Return True-up Adjustment	(6,675)
31	Intercompany Payment	(2,582,859)

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 (c) 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	2025	13		11,858	11,870		1		19,007				2,659,933
2	Federal Insurance Contribution Tax	Federal Insurance Tax	Federal	2025	166,356		4,607,094	4,566,757		206,693		1,947,161				(7,149)
3	Federal Income Tax	Income Tax	Federal	2025	2,616,234		(1,261,965)	(3,991,537)		5,345,806		(1,070,628)				(191,337)
4	State Unemployment Tax	Unemployment Tax	SD	2025	2		9,545	9,540		7		45,477				(35,932)
5	State Income Tax	Income Tax	MT	2025	0		113,914	113,914		0		113,914				
6	Property Tax	Property Tax	SD	2025	5,835,307		4,682,678	4,845,026		5,672,959		4,682,678				
7	Property Tax	Property Tax	WY	2025	942,748		2,634,940	2,840,754		736,934		2,634,939				
8	Property Tax	Property Tax	MT	2025	106,773		515,421	509,656		112,538		515,421				
9	Electric Generation Tax	Other State Tax	WY	2025	0		131,509	131,509		0		131,509				
10	Property Tax	Property Tax	NE	2025	132,453		113,565	141,238		104,780		113,565				
11	Accrued City Franchise Fee	Franchise Tax	WY	2025	0		36,100	36,100		0		36,100				
12	Accrued Sales/Use Tax	Sales And Use Tax	SD	2025	107,348		405,730	400,794		112,284		(2,859)				406,075
13	Accrued Sales/Use Tax	Sales And Use Tax	WY	2025	1,988		76,046	58,187		19,847		(6,778)				81,986
14	Regulatory Tax	Other State Tax	MT	2025	0		56,637	56,637		0		56,637				
40	TOTAL				9,909,222	0	12,133,072	9,730,445	0	12,311,849	0	9,216,143	0	0	0	2,913,576

FOOTNOTE DATA

(a) Concept: TaxesAccruedPrepaidAndCharged

Note: Below is the income tax as adjusted with the income tax effect of non-operating interest expense.

Taxes as booked on FERC:	
Income Taxes- 409.1	(956,714)
Net Interest Expense - Total	31,894,571
Net Interest Expense Already Accounted for in Income Tax	-
Non-Operating Net Interest Expense Needing an Income Tax Adj	31,894,571
Remove Income Tax Effect of Non-Operating Interest Expense	(6,697,860)
Income Taxes- 409.1 As Adjusted	5,741,146

(b) Concept: TaxesAccruedPrepaidAndCharged

Note: Below is the income tax as adjusted with the income tax effect of non-operating interest expense.

Taxes as booked on FERC:	
Income Taxes- 409.1	(956,714)
Net Interest Expense - Total	31,894,571
Net Interest Expense Already Accounted for in Income Tax	-
Non-Operating Net Interest Expense Needing an Income Tax Adj	31,894,571
Remove Income Tax Effect of Non-Operating Interest Expense	(6,697,860)
Income Taxes- 409.1 As Adjusted	5,741,146

(c) Concept: TaxesIncurredOther

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

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	45,393	Various	1,000,009	2,079,343	1,124,727
2	Estimated Contract Liability	1,593,521	426	1,947,832	354,311	0
3	Energy Assistance Program	0		79	1,056	977
47	TOTAL	1,638,914		2,947,920	2,434,710	1,125,704

Name of Respondent:
Black Hills Power Inc.

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

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

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

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating 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										

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				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	164,913,424	7,577,064	6,274,831			182.3	1,914,447	182.3	6,003,708	170,304,918
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	164,913,424	7,577,064	6,274,831				1,914,447		6,003,708	170,304,918
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	164,913,424	7,577,064	6,274,831				1,914,447		6,003,708	170,304,918
10	Classification of TOTAL										
11	Federal Income Tax	164,913,424	7,577,064	6,274,831			182.3	1,914,447	182.3	6,003,708	170,304,918
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	Account Credited	Amount	Account Debited	Amount	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	Account 282										
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	Classification of TOTAL										
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										

(b) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Note: Amounts footnoted are based upon FERC-approved rates

Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits Account Credited (g)	Credits to Other Accounts (Amount (h))	Credits Account Debited (i)	Amount (j)	Balance at End of Year (k)
Account 282										
Electric	\$ 152,741,606	\$ 7,577,064	\$ (1,132,896)				\$ 1,914,448		6,003,708	\$ 165,540,826
Gas										
Other (Define)										
Total	\$ 152,741,606	\$ 7,577,064	\$ (1,132,896)				\$ 1,914,448		\$ 6,003,708	\$ 165,540,826
TOTAL Account 282	\$ 152,741,606	\$ 7,577,064	\$ (1,132,896)				\$ 1,914,448		\$ 6,003,708	\$ 165,540,826
Classification of TOTAL										
Federal Income Tax	\$ 152,741,606	\$ 7,577,064	\$ (1,132,896)			182390	\$ 1,914,448	182390	\$ 6,003,708	\$ 165,540,826
State Income Tax										
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	7,769,890	3,713,903	49,572							11,434,221
4	Employee benefit plans	3,047,701	512,595	595,306							2,964,990
5	Other	2,960,644	29,555	139,183						13,510	2,864,526
6	Regulatory liabilities	5,546,274				182.3	307,894	182,3219.0	1,394,913		6,633,293
9	TOTAL Electric (Total of lines 3 thru 8)	19,324,509	4,256,053	784,061			307,894		1,408,423		23,897,030
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)	19,324,509	4,256,053	784,061			307,894		1,408,423		23,897,030
20	Classification of TOTAL										
21	Federal Income Tax	19,324,509	4,256,053	784,061			307,894		1,408,423		23,897,030
22	State Income Tax										
23	Local Income Tax										

NOTES

(a) 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	Account 283										
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	TOTAL Electric (Total of lines 3 thru 12)	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	Classification of TOTAL										
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										

(b) Concept: AccumulatedDeferredIncomeTaxesOther

Note: Amounts footnoted are based upon FERC-approved rates

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 Account Credited (g)	Amount (h)	Credits Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
16	Employee benefit plans	\$ 3,047,701	\$ 512,595	\$ 595,306							\$ 2,964,990
17	Regulatory Liabilities	\$ 5,436,075	\$ -	\$ -		182390	\$ 307,894	182390;182395;219016	\$ 1,139,062		\$ 6,267,243
18	Deferred Energy Costs	\$ 7,769,890	\$ 3,713,903	\$ 49,572							\$ 11,434,221
19	Other	\$ 2,960,644	\$ 29,555	\$ 139,183					\$ 13,510		\$ 2,864,525
16							\$ -				\$ -
17	TOTAL Electric	\$ 19,214,310	\$ 4,256,053	\$ 784,061			\$ 307,894		\$ 1,152,572		\$ 23,530,979
18	Gas										
19											
20	TOTAL Gas										
21	TOTAL Other										
22	TOTAL	\$ 19,214,310	\$ 4,256,053	\$ 784,061			\$ 307,894		\$ 1,152,572		\$ 23,530,979
23	Classification of TOTAL										
24	Federal Income Tax	\$ 19,214,310	\$ 4,256,053	\$ 784,061			\$ 307,894		\$ 1,152,572		\$ 23,530,979
25	State Income Tax										
26	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	1,370,549	Various	1,334,435	434,448	470,562
2	Protected Property Excess Deferred Income Tax	76,550,664	Various	2,790,589	480,307	74,240,382
3	Non-Protected Property Excess Deferred Income Tax	9,630,345	Various			9,630,345
4	Deferred Taxes related to Pension Plan Regulatory Asset	4,593,356	190.3	112,171	121,771	4,602,956
5	Retiree Healthcare Plan	1,965,219	Various	152,877		1,812,342
41	TOTAL	94,110,133		4,390,072	1,036,526	90,756,587

Name of Respondent:
Black Hills Power Inc.

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

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

FOOTNOTE DATA

(a) Concept: OtherRegulatoryLiabilities

Note: Amounts footnoted are based upon FERC-approved rates. This includes a correction to the beginning balance of 2025 to the correct amount. This matched the amount that was filed in the FERC Formula Rate.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS Account Credited (c)	Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1						
2						
3						
4						
5	Protected Property Excess Deferred Income Tax	\$73,760,463		2,057,079	469,364	\$ 72,172,747
6	Non-Protected Property Excess Deferred Income Tax	\$9,487,889		628,757	10,944	\$ 8,870,077
7						
8						
9						
10						
11						
12						
13						
14						
15	Total	\$ 83,248,352		\$ 2,685,836	\$ 480,308	\$ 81,042,824

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	88,665,190	83,227,703	588,211	580,801	63,983	62,981
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	111,794,958	104,470,401	797,356	789,308	14,263	14,147
5	Large (or Ind.) (See Instr. 4)	39,398,856	38,812,842	440,984	467,005	23	24
6	(444) Public Street and Highway Lighting	1,230,344	1,209,259	9,800	9,921	230	219
7	(445) Other Sales to Public Authorities	2,382,837	2,364,883	21,619	22,970	156	152
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	243,472,185	230,085,088	1,857,970	1,870,005	78,655	77,523
11	(447) Sales for Resale	41,734,479	33,318,259	830,439	689,637	322	419
12	TOTAL Sales of Electricity	285,206,664	263,403,347	2,688,409	2,559,642	78,977	77,942
13	(Less) (449.1) Provision for Rate Refunds		8				
14	TOTAL Revenues Before Prov. for Refunds	285,206,664	263,403,339	2,688,409	2,559,642	78,977	77,942
15	Other Operating Revenues						
16	(450) Forfeited Discounts	297,965	274,897				
17	(451) Miscellaneous Service Revenues	444,960	447,326				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	20,348,887	21,858,902				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	1,247,983	1,070,059				
22	(456.1) Revenues from Transmission of Electricity of Others	40,924,863	42,019,022				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	63,264,658	65,670,206				
27	TOTAL Electric Operating Revenues	348,471,322	329,073,545				

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: 12/31/2025	Year/Period of Report End of: 2025/ 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

Name of Respondent:
Black Hills Power Inc.

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

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ 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					
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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	122	8,503	12	10,167	0.070
2	SD887 - Net Billing Total Electric Max	418	42,628	19	22,000	0.102
3	SDA24 - Private Area Lighting-A	743	115,871	71	10,465	0.156
4	SDB24 - Private Area Lighting-B	63	13,700	2	31,500	0.217
5	SDC24 - Private Area Lighting-C	2	125			0.063
6	WY798 - Rental		130			
7	WY910 - Regular Service	14,126	1,730,826	1,542	9,161	0.123
8	WY911 - BHP Residential	4	618	1	4,000	0.155
9	WY912 -Total Electric	4,122	483,801	353	11,677	0.117
10	WY913 - Total Electric	8	1,005	1	8,000	0.126
11	WY914 - Demand Service	181	22,258	11	16,455	0.123
12	SD710 - Regular Service	391,180	50,519,498	49,933	7,834	0.129
13	WY916 - Demand Service Max	1,501	176,840	83	18,084	0.118
14	WYA24 - Private Area Lighting-A	37	7,186	6	6,167	0.194
15	Energy Cost Adjustment		17,782,591			
16	SD712 - Total Electric	94,116	9,826,695	7,849	11,991	0.104
17	SD714 - Demand Service	15,008	1,563,749	836	17,952	0.104
18	SD716 - Demand Service Max	63,154	5,948,010	3,049	20,713	0.094
19	SD717 - Utility Controlled	124	7,757	1	124,000	0.063
20	SD799 - Rental		1,845	3		
21	SD875 - Regular Service	886	121,669	104	8,519	0.137
22	SD876 - Net Billing Total Electric	789	95,698	107	7,374	0.121
41	TOTAL Billed Residential Sales	586,584	88,471,003	63,983	9,168	0.151
42	TOTAL Unbilled Rev. (See Instr. 6)	1,627	194,187			0.119
43	TOTAL	588,211	88,665,190	63,983	9,193	0.151

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	305	30,854	22	13,864	0.101
2	SD731 - Large General Service	39,953	3,157,988	6	6,658,833	0.079
3	SD750 - Small Interruptible General Service	41	4,424	1	41,000	0.108
4	SD755 - Energy Storage Service	12,189	893,855	32	380,906	0.073
5	SD770 - General Service-Special Events	1,627	265,064	137	11,876	0.163
6	SD771 - Large General Service	24,149	1,813,897	1	24,149,000	0.075
7	SD798 - Rental		2,582	2		
8	SD799 - Rental		23,145	42		
9	SD826 - Large General Service	11,124	1,135,587	30	370,800	0.102
10	SD827 - Large General Service	179,433	14,838,588	122	1,470,762	0.083
11	SD878 - Net Billing General Service	1,369	179,008	26	52,654	0.131
12	MT923 - General Service-Total Electric	8	710	2	4,000	0.089
13	SD879 - General Service	48	6,921	1	48,000	0.144
14	SD890 - Large General Service	434	56,130	1	434,000	0.129
15	SDA24 - Private Area Lighting-A	1,677	232,013	235	7,136	0.138
16	SDB24 - Private Area Lighting-B	632	124,616	44	14,364	0.197
17	SDC24 - Private Area Lighting-C	123	8,872	9	13,667	0.072
18	WY798 - Rental		975	2		
19	WY918 - General Service-No Demand	29	3,673	3	9,667	0.127
20	WY920 - General Service	44,695	4,977,914	542	82,463	0.111
21	WY921 - Large General Service-Secondary	2,231	237,797	3	743,667	0.107
22	WY923 - General Service-Total Electric	1,055	119,621	40	26,375	0.113
23	SD718 - General Service-No Demand	832	89,203	55	15,127	0.107
24	WYA24 - Private Area Lighting-A	65	12,621	7	9,286	0.194
25	WYB24 - Private Area Lighting-B	38	8,578	1	38,000	0.226
26	Energy Cost Adjustment		23,929,202			
27	Renewable Ready		1,643,330			
28	SD720 - General Service	363,160	46,449,949	11,917	30,474	0.128
29	SD721 - Large General Service-Secondary	75,721	7,476,087	89	850,798	0.099
30	SD722 - Large Demand Curtailable Service	609	46,743	1	609,000	0.077
31	SD723 - General Service-Total Electric	31,797	3,579,320	849	37,452	0.113
32	SD726 - Irrigation Pumping	660	104,665	29	22,759	0.159
33	SD727 - Utility Controlled General Service	1,308	89,206	12	109,000	0.068
41	TOTAL Billed Small or Commercial	795,312	111,543,138	14,263	55,760	0.140
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	2,044	251,820			0.123
43	TOTAL Small or Commercial	797,356	111,794,958	14,263	55,904	0.140

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: 12/31/2025	Year/Period of Report End of: 2025/ 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	34	2,820	3	11,333	0.083
2	SDB24 - Private Area Lighting-B	2	490			0.245
3	WY798 - Rental		305			
4	WY921 - General Service Large	6,152	774,880	1	6,152,000	0.126
5	WY931 - Industrial Contract Services	51,286	3,621,575	1	51,286,000	0.071
6	WY934 - General Service Large	44,404	3,873,685	8	5,550,500	0.087
7	WYB24 - Private Area Lighting-B	11	2,568	1	11,000	0.233
8	Energy Cost Adjustment		8,113,838			
9	Renewable Ready		1,545,527			
10	MT930 - General Service Large	3,468	286,609	1	3,468,000	0.083
11	MT931 - General Service Large	23,010	1,709,151	2	11,505,000	0.074
12	MT932 - General Service Large	132,384	8,243,621	1	132,384,000	0.062
13	SD720 - General Service	233	25,118	2	116,500	0.108
14	SD761 - Industrial Contract Transmission	106,685	6,078,699	1	106,685,000	0.057
15	SD764 - Industrial Contract Services-Forest Products-Primary	20,077	1,564,813	1	20,077,000	0.078
16	SD774 - Industrial Contract Services-Forest Products-Primary	51,387	3,369,320	1	51,387,000	0.066
17	SDA24 - Private Area Lighting-A	2	316			0.158
41	TOTAL Billed Large (or Ind.) Sales	439,135	39,213,335	23	19,092,826	0.089
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	1,849	185,521			0.100
43	TOTAL Large (or Ind.)	440,984	39,398,856	23	19,173,217	0.089

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: 12/31/2025	Year/Period of Report End of: 2025/ 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	5,908	421,456	27	218,815	0.071
2	SD742 - Traffic Signals	685	76,218	146	4,692	0.111
3	SD798 - Rental		240			
4	SD799 - Rental		16,062	6		
5	SD840 - Company Owned Service	2,769	629,638	38	72,868	0.227
6	SD841 - Customer Owned Service	110	11,058	4	27,500	0.101
7	SDA24 - Private Area Lighting	8	1,213	2	4,000	0.152
8	SDB24 - Private Area Lighting	1	269			
9	SDC24 - Private Area Lighting	8	671	2	4,000	
10	WY940 - Company Owned Service	253	67,532			0.267
11	WY941 - Customer Owned Service	49	4,209	1	49,000	0.086
12	WY942 - Traffic Signals	9	1,778	4	2,250	0.198
41	TOTAL Billed Public Street and Highway Lighting	9,800	1,230,344	230	42,609	0.126
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	9,800	1,230,344	230	42,609	0.126

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	Energy Cost Adjustment		406,626			
2	Renewable Ready		21,427			
3	SD720 - Municipal Pumping	822	121,864	51	16,118	0.148
4	SD723 - Municipal Pumping	10	1,442	2	5,000	0.144
5	SD726 - Municipal Pumping	17	3,441	1	17,000	0.202
6	SD743 - Municipal Pumping	20,159	1,759,040	93	216,763	0.087
7	WY943 - Municipal Pumping	376	47,148	9	41,778	0.125
41	TOTAL Billed Other Sales to Public Authorities	21,384	2,360,988	156	137,077	0.110
42	TOTAL Unbilled Rev. (See Instr. 6)	235	21,849			0.093
43	TOTAL	21,619	2,382,837	156	138,583	0.110

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					

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: 12/31/2025	Year/Period of Report End of: 2025/ Q4
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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	1,852,215	242,818,808	78,655	23,549	0.131
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	5,755	653,377			0.114
43	TOTAL - All Accounts	1,857,970	243,472,185	78,655	23,622	0.131

SALES FOR RESALE (Account 447)

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

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

 LF - for long-term service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or 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.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the last line of the schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the last line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.
10. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Total (\$) (h++)(k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)	
1	City of Gillette Wyoming	RQ	34	23	23	23	200,332		7,890,086		7,890,086
2	Montana Dakota Utilities	RQ	3	47	47	47	290,927	2,057,149	10,938,502	=(996)	12,994,655
3	Municipal Energy Agency of Nebraska (MEAN)	LU	3				101,352		6,525,587		6,525,587
4	Western Area Power Administration - Loveland Area Power	OS	3				103,855		5,432,074		5,432,074
5	Western Area Power Administration - Colorado River Storage Project	OS	3				30,816		1,503,402		1,503,402
6	Western Area Power Administration - Western Area Colorado Missouri Marketing	OS	3				5,347		506,822		506,822
7	Western Area Colorado Missouri - North West Power Pool	OS	3				845		36,072		36,072
8	Altop Energy	OS	3				347		24,984		24,984
9	Arizona Electric Power	OS	3						252		252
10	Basin Electric Power	OS	3				14,700		699,304		699,304
11	³⁴ Cheyenne Light, Fuel, and Power	OS	3				5,205		74,018		74,018
12	Colorado Springs Utilities	OS	3				975		51,850		51,850
13	Eagle Energy	OS	3				240		17,280		17,280
14	Guzman Energy	OS	3				3,882		162,159		162,159
15	Macquarie Energy	OS	3				3,156		140,488		140,488
16	Mercuria	OS	3				2,856		96,292		96,292
17	Morgan Stanley	OS	3				700		42,000		42,000
18	Northwestern Energy	OS	3				60		1,800		1,800
19	Pacificorp	OS	3				16,106		778,137		778,137
20	Phillips 66	OS	3				5,562		236,420		236,420
21	Platte River Power Authority	OS	3				1,508		71,880		71,880
22	Public Service Company of Colorado	OS	3				5,238		301,925		301,925
23	Public Service Company of New Mexico	OS	3				66		7,352		7,352
24	Salt River Project	OS	3				22		1,320		1,320
25	Southwest Power Pool - Western Energy Imbalance Service	OS	SPP RTO				1,783		70,107	=(2,550,920)	2,621,027
26	The Energy Authority	OS	3				400		14,000		14,000
27	The Energy Authority - Municipal Energy Agency of Nebraska (MEAN)	OS	3				5,323		230,365		230,365
28	Tri-State Generation	OS	3				2,691		124,520		124,520
29	United Power	OS	3				26,120		1,146,908		1,146,908
30	Utah Municipal Power Agency	OS	3				25		1,500		1,500

15	Subtotal - RQ					491,259	2,057,149	18,828,588	(996)	20,884,741
16	Subtotal-Non-RQ					339,180	0	18,298,818	2,550,920	20,849,738
17	Total					830,439	2,057,149	37,127,406	2,549,924	41,734,479

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: 12/31/2025	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

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

Name of Respondent:
Black Hills Power Inc.

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

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,736,939	1,508,229
5	(501) Fuel	19,371,470	23,159,864
6	(502) Steam Expenses	1,041,167	1,522,637
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	709,697	621,093
10	(506) Miscellaneous Steam Power Expenses	1,413,212	1,463,942
11	(507) Rents	3,842,321	3,734,366
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	28,114,806	32,010,131
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	638,616	840,054
16	(511) Maintenance of Structures	724,375	827,704
17	(512) Maintenance of Boiler Plant	5,442,872	5,660,096
18	(513) Maintenance of Electric Plant	2,864,062	1,219,168
18.1	(513.1) Maintenance of Computer Hardware	6,282	
18.2	(513.2) Maintenance of Computer Software	126,592	
18.3	(513.3) Maintenance of Communication Equipment	733	
19	(514) Maintenance of Miscellaneous Steam Plant	159,517	81,085
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	9,963,049	8,628,107
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	38,077,855	40,638,238
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
38.1	(531.1) Maintenance of Computer Hardware		
38.2	(531.2) Maintenance of Computer Software		
38.3	(531.3) Maintenance of Communication Equipment		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
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		
56.1	(544.1) Maintenance of Computer Hardware		
56.2	(544.2) Maintenance of Computer Software		
56.3	(544.3) Maintenance of Communication Equipment		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
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	958,999	1,164,352
63	(547) Fuel	17,249,009	12,640,453
64	(548) Generation Expenses	1,109,351	1,399,245
65	(549) Miscellaneous Other Power Generation Expenses	364,697	226,243
66	(550) Rents	2,249,395	2,409,945
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	21,931,451	17,840,238
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	392	739
70	(552) Maintenance of Structures	12,731	242
71	(553) Maintenance of Generating and Electric Plant	3,623,913	2,384,974
71.1	(553.1) Maintenance of Computer Hardware	189	
71.2	(553.2) Maintenance of Computer Software	111,322	
71.3	(553.3) Maintenance of Communication Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	34,882	12,567
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	3,783,429	2,398,522
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	25,714,880	20,238,760
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	52,607,451	28,258,548
76.1	(555.1) Power Purchased for Storage Operations		
76.2	(555.2) Bundled Environmental Credits		
76.3	(555.3) Unbundled Environmental Credits		
77	(556) System Control and Load Dispatching	1,469,727	1,566,220
78	(557) Other Expenses		3,546
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	54,077,178	29,828,314
79.1	F. Solar Generation		
79.2	Operation		
79.3	(558.1) Operation Supervision and Engineering	702,997	
79.4	(558.2) Solar Panel Generation and Other Plant Operating Expenses	9,051	
79.6	(558.4) Rents		
79.7	TOTAL Operation (Enter Total of lines 79.3 thru 79.6)	712,048	
79.8	Maintenance		
79.9	(558.6) Maintenance Supervision and Engineering		
79.10	(558.7) Maintenance of Solar Panels, Structures, and Equipment		
79.11	(558.8) Maintenance of Computer Hardware		
79.12	(558.9) Maintenance of Computer Software		
79.13	(558.10) Maintenance of Communication Equipment		
79.14	(558.11) Maintenance of Miscellaneous Solar Generation Plant		
79.15	TOTAL Maintenance (Enter Total of lines 79.9 thru 79.14)		
79.16	TOTAL Power Production Expenses-Solar (total of lines 79.7 & 79.15)	712,048	

79.17	G. Wind Generation		
79.18	Operation		
79.19	(558.13) Operation Supervision and Engineering		
79.20	(558.14) Wind Turbine Generation and Other Plant Operating Expenses		
79.21	(558.16) Rents		
79.22	TOTAL Operation (Enter Total of lines 79.19 thru 79.21)		
79.23	Maintenance		
79.24	(558.18) Maintenance Supervision and Engineering		
79.25	(558.19) Maintenance of Wind Turbines, Structures, and Equipment		
79.26	(558.20) Maintenance of Computer Hardware		
79.27	(558.21) Maintenance of Computer Software		
79.28	(558.22) Maintenance of Communication Equipment		
79.29	(558.23) Maintenance of Miscellaneous Wind Generation Plant		
79.30	TOTAL Maintenance (Enter Total of lines 79.24 thru 79.29)		
79.31	TOTAL Power Production Expenses-Wind (total of lines 79.22 & 79.30)		
79.32	H. Other Renewable Generation		
79.33	Operation		
79.34	(559.1) Operation Supervision and Engineering		
79.35	(559.2) Other Miscellaneous Generation and Other Plant Operating Expenses		
79.36	(559.3) Fuel		
79.37	(559.4) Rents		
79.38	TOTAL Operation (Enter Total of lines 79.34 thru 79.37)		
79.39	Maintenance		
79.40	(559.6) Maintenance Supervision and Engineering		
79.41	(559.7) Maintenance of Structures		
79.42	(559.9) Maintenance of Boilers		
79.43	(559.10) Maintenance of Generating and Electric Equipment		
79.44	(559.12) Maintenance of Computer Hardware		
79.45	(559.13) Maintenance of Computer Software		
79.46	(559.14) Maintenance of Communication Equipment		
79.47	(559.15) Maintenance of Miscellaneous Renewable Production Plant		
79.48	TOTAL Maintenance (Enter Total of lines 79.40 thru 79.47)		
79.49	TOTAL Power Production Expenses-Other Renewable (total of lines 79.38 & 79.48)		
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74, 79, 79.16, 79.31, & 79.49)	118,581,961	90,705,312
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	534,729	677,753
85	(561.1) Load Dispatch-Reliability	126,603	131,592
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,241,477	1,097,784
87	(561.3) Load Dispatch-Transmission Service and Scheduling	60,253	85,779
88	(561.4) Scheduling, System Control and Dispatch Services	367,372	328,179
89	(561.5) Reliability, Planning and Standards Development	931,293	736,577
90	(561.6) Transmission Service Studies	18,705	15,012
91	(561.7) Generation Interconnection Studies	46,584	64,577
92	(561.8) Reliability, Planning and Standards Development Services	170,351	129,633
93	(562) Station Expenses	377,529	359,692
94	(563) Overhead Lines Expenses	21,513	38,715
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	25,870,553	27,662,909
97	(566) Miscellaneous Transmission Expenses	855,913	617,888
98	(567) Rents	81,543	68,331
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	31,704,418	32,014,421
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	131	65
102	(569) Maintenance of Structures	33,561	19,597
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	176,063	151,257
108	(571) Maintenance of Overhead Lines	146,285	120,363
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of Lines 101 thru 110)	356,040	291,282
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	32,060,458	32,305,703
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation	152,098	151,733
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)	152,098	151,733
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)	152,098	151,733
131.1	4. ENERGY STORAGE EXPENSES		
131.2	Operation		
131.3	(577.1) Operation Supervision and Engineering		
131.4	(577.2) Operation of Energy Storage Equipment		
131.5	(577.3) Storage Fuel		
131.6	(577.4) Rents		
131.7	Total Operation (Lines 131.3 thru 131.6)		
131.8	Maintenance		
131.9	(578.1) Maintenance Supervision and Engineering		
131.10	(578.2) Maintenance of Energy Storage Equipment and Structures		
131.11	(578.3) Maintenance of Computer Hardware		
131.12	(578.4) Maintenance of Computer Software		
131.13	(578.5) Maintenance of Communication Equipment		
131.14	(578.6) Maintenance of Miscellaneous Other Energy Storage Plant		
131.15	Total Maintenance (Lines 131.9 thru 131.14)		
131.16	TOTAL Energy Storage Expenses (Total of 131.7 and 131.15)		
132	5. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,214,110	1,060,788
135	(581) Load Dispatching	588,138	620,169
136	(582) Station Expenses	659,322	690,830
137	(583) Overhead Line Expenses	578,249	365,832
138	(584) Underground Line Expenses	500,747	465,780
139	(585) Street Lighting and Signal System Expenses	21,684	62,839
140	(586) Meter Expenses	706,380	564,446
141	(587) Customer Installations Expenses	436,880	572,870
142	(588) Miscellaneous Expenses	2,268,042	2,067,057
143	(589) Rents	9,812	12,478
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	6,983,364	6,483,089
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	7,365	7,501
147	(591) Maintenance of Structures		

148	(592) Maintenance of Station Equipment		272,878	240,657
148.1	(592.2) Maintenance of Computer Hardware			
148.2	(592.3) Maintenance of Computer Software			
148.3	(592.4) Maintenance of Communication Equipment			
149	(593) Maintenance of Overhead Lines		6,737,046	5,300,636
150	(594) Maintenance of Underground Lines		335,082	379,829
151	(595) Maintenance of Line Transformers		88,923	80,026
152	(596) Maintenance of Street Lighting and Signal Systems		54,083	6,267
153	(597) Maintenance of Meters		5,872	266
154	(598) Maintenance of Miscellaneous Distribution Plant		249	9,930
155	TOTAL Maintenance (Total of Lines 146 thru 154)		7,501,498	6,025,112
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)		14,484,862	12,508,201
157	6. CUSTOMER ACCOUNTS EXPENSES			
158	Operation			
159	(901) Supervision		78,574	77,347
160	(902) Meter Reading Expenses		64,741	161,410
161	(903) Customer Records and Collection Expenses		1,183,801	1,156,306
162	(904) Uncollectible Accounts		414,133	448,010
163	(905) Miscellaneous Customer Accounts Expenses		336,368	261,431
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)		2,077,617	2,104,504
165	7. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES			
166	Operation			
167	(907) Supervision		60,664	50,504
168	(908) Customer Assistance Expenses		840,976	548,897
169	(909) Informational and Instructional Expenses		16,527	6,977
170	(910) Miscellaneous Customer Service and Informational Expenses		492	1,206
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)		918,659	607,584
172	8. SALES EXPENSES			
173	Operation			
174	(911) Supervision			
175	(912) Demonstrating and Selling Expenses		5,487	2,709
176	(913) Advertising Expenses		74	
177	(916) Miscellaneous Sales Expenses			
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)		5,561	2,709
179	9. ADMINISTRATIVE AND GENERAL EXPENSES			
180	Operation			
181	(920) Administrative and General Salaries		14,853,310	13,933,613
182	(921) Office Supplies and Expenses		4,266,333	4,719,618
183	(Less) (922) Administrative Expenses Transferred-Credit		3,378,747	3,599,865
184	(923) Outside Services Employed		3,131,527	2,942,836
185	(924) Property Insurance		1,234,517	1,443,406
186	(925) Injuries and Damages		3,493,949	3,065,149
187	(926) Employee Pensions and Benefits		6,628,274	6,032,159
188	(927) Franchise Requirements			
189	(928) Regulatory Commission Expenses		1,171,614	1,035,201
190	(929) (Less) Duplicate Charges-Cr.		745,017	707,630
191	(930.1) General Advertising Expenses		427,655	376,213
192	(930.2) Miscellaneous General Expenses		955,967	1,146,795
193	(931) Rents		1,502,539	1,948,676
194	TOTAL Operation (Enter Total of Lines 181 thru 193)		33,541,921	32,336,171
195	Maintenance			
196	(935) Maintenance of General Plant		3,497,683	2,884,040
196.1	(935.1) Maintenance of Computer Hardware		13	
196.2	(935.2) Maintenance of Computer Software		54,477	
196.3	(935.3) Maintenance of Communication Equipment			
196.4	TOTAL Maintenance (Enter Total of lines 196 thru 196.3)		3,552,173	2,884,040
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196.4)		37,094,094	35,220,211
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 131.16, 156, 164, 171, 178, and 197)		205,375,310	173,605,957

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	Pacificcorp	OS	181				25,817						819,742		819,742
2	Altop Energy	OS					3,243						229,087		229,087
3	Arizona Electric Power	OS					1,640						32,320		32,320
4	Arizona Public Service	OS											3,960		3,960
5	Basin Electric Power	OS					301,015						12,908,007		12,908,007
6	²⁰ Cheyenne Light, Fuel, and Power	OS					4,081						65,943		65,943
7	²⁰ Cheyenne Light, Fuel, and Power - Happy Jack Wind	OS					31,031						1,663,121		1,663,121
8	²⁰ Cheyenne Light, Fuel, and Power - Silver Sage Wind	OS					52,060						3,655,478		3,655,478
9	Citigroup	OS					3,330								
10	Colorado Spring Utilities	OS					7,265						365,995		365,995
11	Corriedale Wind	OS					132,875						4,023,604		4,023,604
12	Dynasty Power	OS					3,075						220,464		220,464
13	Eagle Energy	OS					2,200						91,080		91,080
14	Energy Keepers	OS					288						6,912		6,912
15	Fall River Solar	OS					171,245						5,479,831		5,479,831
16	Guzman Energy	OS					68,264						4,218,135		4,218,135
17	Idaho Power	OS					1,187						26,659		26,659
18	Macquarie Energy	OS					167,728						7,575,323		7,575,323
19	Mercuria	OS					77,009						2,690,728		2,690,728
20	Nevada Power	OS					1						35		35
21	Morgan Stanley	OS					3,094						196,010		196,010
22	Northwestern Energy	OS					40						(14,660)		(14,660)
23	Phillips 66 Energy	OS					25,140						1,161,062		1,161,062
24	Platte River Power Authority	OS					6,120						299,048		299,048
25	Platte River Power Authority - Silver Sage Wind	OS					31,272						625,345		625,345
26	Portland General Electric	OS					55						3,850		3,850
27	Public Service Company of Colorado	OS					7,444						252,765		252,765

28	Public Service Company of New Mexico	OS					435						(801)	(801)	
29	Rainbow Energy	OS					80						1,600	1,600	
30	Salt River Project	OS					337						22,235	22,235	
31	Seattle City Light	OS					1,960						26,400	26,400	
32	Southwest Power Pool	OS					73,097						711,412	711,412	
33	Southwest Power Pool - Western Energy Imbalance System (WEIS)	OS	SPP RTO										3,423,980	3,423,980	
34	Spearfish, (City of) - Spearfish Hydro	OS					18,398						625,676	625,676	
35	City of St. George	OS					220						5,050	5,050	
36	The Energy Authority (MEAN)	OS					111						3,045	3,045	
37	The Energy Authority (West)	OS					773						34,150	34,150	
38	Tenaska Power	OS					15						120	120	
39	TransAlta Energy	OS					300						4,800	4,800	
40	Tri State Generation	OS					6,490						235,868	235,868	
41	United Power	OS					100						2,871	2,871	
42	Utah Municipal Power Agency	OS					9,553						522,905	522,905	
43	Western Area Power Administration - Colorado River Storage Project	OS					1,526						26,108	26,108	
44	Western Area Power Administration - Loveland Area Power	OS					16,399						219,028	219,028	
45	Western Area Colorado Missouri - North West Power Pool	OS					342						4,895	4,895	
46	Western Area Power Administration - Western Area Colorado Missouri Marketing	OS					105						210	210	
47	Western Area Power Administration	EX							315,233	228,233			114,321	114,321	
48	Renewable Energy Rate 44	OS											23,734	23,734	
15	TOTAL						1,256,760		315,233	228,233			49,069,150	3,538,301	52,607,451

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: 12/31/2025	Year/Period of Report End of: 2025/ 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
Other charges - 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 megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		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		3,128	3,128	3,292,800				3,292,800
2	Black Hills Power	Black Hills Power	Black Hills Power	FNS	11	Various	Various		2,018,289	2,018,289		10,227,076	1,705,823		11,932,899
3	Basin Electric Power	Black Hills Power	Basin Electric Power	FNO	11	Various	Various		2,094,157	2,094,157			8,737,738	1,913,273	10,651,011
4	Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power (2)	FNO	11	Various	Various								
5	City of Gillette	Black Hills Power	City of Gillette	FNO	11	Various	Various		354,203	354,203		1,876,794	399,588		2,276,382
6	State of South Dakota	Black Hills Power	South Dakota State of	FNO	11	Various	Various		17,429	17,429		82,146	13,007		95,153
7	Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power (2), Basin Electric Power	LFP	7	WYODAK	SGW		1,018,769	1,018,769	4,838,680			1,099,849	5,938,529
8	Municipal Energy Agency of Nebraska (MEAN)	Black Hills Power	MEAN, Western Area Power Administration-LAP	LFP	7	WYODAK, WY69	SGW		219,313	219,313	1,114,170			199,168	1,313,338
9	Basin Electric Power	Black Hills Power	Basin Electric Power	LFP	7	DRYFORK	RC		34,725	34,725	3,373,101			586,256	3,959,357
10	Basin Electric Power	Black Hills Power	Wyoming Municipal Power Agency	LFP	7	DRYFORK	DJ		8,697	8,697	844,805			146,830	991,635
11	Basin Electric Power	Black Hills Power	Basin Electric Power	SFP	7	DRYFORK	DJ		2,443	2,443		12,211	488		12,699
12	Basin Electric Power	Black Hills Power	Basin Electric Power	SFP	7	DRYFORK	SGW		621	621		3,104	124		3,228
13	Basin Electric Power	Black Hills Power	Basin Electric Power	SFP	7	SGW	WSTAR		1	1		5			5
14	Basin Electric Power	Black Hills Power	Basin Electric Power	SFP	7	WSTAR	DJ		1	1		5			5
15	Black Hills Power	Black Hills Power	Black Hills Power	SFP	7	SGW	RC		307	307		1,734	121		1,855
16	Black Hills Power	Black Hills Power	Black Hills Power	SFP	7	SGW	SHERIDAN		20	20		113	8		121
17	Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel, and Power	SFP	7	WYODAK	DJ		2,940	2,940		11,821	489		12,310
18	CP Energy Marketing	Black Hills Power	CP Energy Marketing	SFP	7	DJ	RC		200	200		725	37		762
19	MAG Energy Solutions	Black Hills Power	MAG Energy Solutions	SFP	7	RC	DJ		215	215		1,065	31		1,096
20	PacifiCorp	Black Hills Power	PacifiCorp	SFP	7	DJ	WYODAK		1,690	1,690		8,079	426		8,505
21	PacifiCorp	Black Hills Power	PacifiCorp	SFP	7	WYODAK	DJ		43,421	43,421		207,574	10,938		218,512
22	PacifiCorp	Black Hills Power	PacifiCorp	SFP	7	WYODAK	WYODAK		540	540		2,581	136		2,717
23	PacifiCorp	Black Hills Power	PacifiCorp	SFP	7	WYODAK	WSTAR		10,788	10,788		51,572	2,718		54,290
24	PacifiCorp	Black Hills Power	PacifiCorp	SFP	7	WSTAR	ANTELOPE		10,788	10,788		51,572	2,718		54,290
25	Public Service Company of Colorado	Black Hills Power	Public Service Company of Colorado	SFP	7	RC	DJ		50	50		181	9		190
26	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	SFP	7	DJ	RC		134	134		837	84		921
27	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	SFP	7	SGW	RC		5	5		31	3		34
28	Shell Energy North America	Black Hills Power	Shell Energy North America	SFP	7	DJ	RC		25	25		159	3		162
29	The Energy Authority	Black Hills Power	The Energy Authority	SFP	7	DJ	RC		290	290		1,321	136		1,457
30	The Energy Authority	Black Hills Power	The Energy Authority	SFP	7	RC	DJ		1,038	1,038		4,730	488		5,218
31	TransAlta Energy Marketing U.S.Inc.	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	SFP	7	DJ	RC		389	389		2,128	228		2,356
32	MFT Energy US Power LLC	Black Hills Power	MFT Energy US Power LLC	SFP	7	DJ	RC		300	300		1,904	31		1,935
33	Altop Energy	Black Hills Power	Altop Energy	NF	8	DJ	RC		571	571		362	340		702

34	Altop Energy	Black Hills Power	Altop Energy	NF	8	RC	DJ		340	340		216	203	419
35	Altop Energy	Black Hills Power	Altop Energy	NF	8	RC	SGW		294	294		187	175	362
36	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DJ	DRYFORK		241	241		153	67	220
37	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DJ	RC		2,340	2,340		1,485	646	2,131
38	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DJ	SGW		450	450		286	124	410
39	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DJ	WYODAK		1,149	1,149		729	317	1,046
40	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DRYFORK	DJ		34,449	34,449		21,865	9,512	31,377
41	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DRYFORK	RC		23,416	23,416		14,863	6,466	21,329
42	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DRYFORK	SGW		48,829	48,829		30,993	13,483	44,476
43	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DRYFORK	SHERIDAN		255	255		162	70	232
44	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	DRYFORK	WYODAK		18	18		11	5	16
45	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	RC	DJ		25	25		16	7	23
46	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	RC	DRYFORK		180	180		114	50	164
47	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	RC	WYODAK		530	530		336	146	482
48	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	SGW	DJ		2,558	2,558		1,624	706	2,330
49	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	SGW	DRYFORK		161	161		102	45	147
50	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	SGW	RC		342	342		217	94	311
51	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	SGW	SHERIDAN		931	931		591	257	848
52	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	SGW	WYODAK		802	802		509	221	730
53	Basin Electric Power	Black Hills Power	Basin Electric Power	NF	8	WYODAK	WYODAK		340	340		216	94	310
54	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	DJ	RC		260,500	260,500		165,351	85,928	251,279
55	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	DJ	SHERIDAN		486	486		308	160	468
56	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	DJ	WYODAK		398	398		253	131	384
57	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	DRYFORK	DJ		2,221	2,221		1,410	733	2,143
58	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	DRYFORK	RC		78,673	78,673		49,937	25,951	75,888
59	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	DRYFORK	SGW		1,075	1,075		682	355	1,037
60	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	DRYFORK	SHERIDAN		33,583	33,583		21,317	11,078	32,395
61	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	RC	DJ		2,167	2,167		1,375	715	2,090
62	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	RC	SGW		5,694	5,694		3,614	1,878	5,492
63	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	RC	SHERIDAN		2,890	2,890		1,834	953	2,787
64	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	RC	WYODAK		8,240	8,240		5,230	2,718	7,948
65	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	RC	ANTELOPE		26	26		17	9	26
66	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	SGW	RC		84,183	84,183		53,435	27,769	81,204
67	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	SGW	SHERIDAN		383	383		243	126	369
68	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	SGW	WYODAK		15	15		10	5	15
69	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	WYODAK	DJ		151,635	151,635		96,250	50,018	146,268
70	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	WYODAK	RC		4,052	4,052		2,572	1,337	3,909
71	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	WYODAK	SGW		68,502	68,502		43,481	22,596	66,077
72	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	WYODAK	SHERIDAN		11,418	11,418		7,248	3,766	11,014
73	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	WYODAK	WYODAK		816	816		518	269	787
74	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	WYODAK	ANTELOPE		2,631	2,631		1,670	868	2,538
75	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	ANTELOPE	SHERIDAN		26	26		17	9	26
76	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	FALLRIVER	RC		150	150		95	50	145
77	Black Hills Power	Black Hills Power	Black Hills Power	NF	8	FALLRIVER	SGW		3,772	3,772		2,394	1,244	3,638
78	Black Hills Wyoming	Black Hills Power	Black Hills Wyoming	NF	8	DRYFORK	SHERIDAN		624	624		396	59,583	59,979
79	Black Hills Wyoming	Black Hills Power	Black Hills Wyoming	NF	8	RC	WYODAK		11	11		7	1,050	1,057
80	Black Hills Wyoming	Black Hills Power	Black Hills Wyoming	NF	8	WYODAK	SGW		300	300		190	28,646	28,836
81	Black Hills Wyoming	Black Hills Power	Black Hills Wyoming	NF	8	WYODAK	WYODAK		90	90		57	8,594	8,651
82	Black Hills Colorado Electric	Black Hills Power	Black Hills/Colorado Electric	NF	8	DRYFORK	DJ		30	30		19	19	38

83	Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power	NF	8	DJ	SGW		160	160		102	53	155
84	Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power	NF	8	DRYFORK	DJ		442	442		281	147	428
85	Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power	NF	8	DRYFORK	SGW		4,785	4,785		3,037	1,589	4,626
86	Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power	NF	8	WYODAK	DJ		3,662	3,662		2,324	1,216	3,540
87	Cheyenne Light, Fuel and Power	Black Hills Power	Cheyenne Light, Fuel and Power	NF	8	WYODAK	SGW		6,291	6,291		3,993	2,089	6,082
88	CP Energy Marketing	Black Hills Power	CP Energy Marketing	NF	8	DJ	RC		135	135		86	21	107
89	CP Energy Marketing	Black Hills Power	CP Energy Marketing	NF	8	RC	DJ		300	300		190	47	237
90	Dynasty Power Inc.	Black Hills Power	Dynasty Power Inc.	NF	8	DJ	RC		9,129	9,129		5,794	2,659	8,453
91	Dynasty Power Inc.	Black Hills Power	Dynasty Power Inc.	NF	8	DJ	SGW		1,231	1,231		781	359	1,140
92	Dynasty Power Inc.	Black Hills Power	Dynasty Power Inc.	NF	8	RC	DJ		22,647	22,647		14,373	6,597	20,970
93	Dynasty Power Inc.	Black Hills Power	Dynasty Power Inc.	NF	8	RC	SGW		1,073	1,073		681	313	994
94	Dynasty Power Inc.	Black Hills Power	Dynasty Power Inc.	NF	8	RC	WYODAK		1,350	1,350		857	393	1,250
95	Dynasty Power Inc.	Black Hills Power	Dynasty Power Inc.	NF	8	RC	ANTELOPE		2,389	2,389		1,516	696	2,212
96	Dynasty Power Inc.	Black Hills Power	Dynasty Power Inc.	NF	8	SGW	RC		1,526	1,526		968	445	1,413
97	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	DJ	RC		5,414	5,414		3,436	1,559	4,995
98	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	DJ	SGW		880	880		558	253	811
99	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	RC	DJ		60,659	60,659		38,498	17,462	55,960
100	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	RC	SGW		16,010	16,010		10,161	4,609	14,770
101	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	RC	WYODAK		3	3		2	1	3
102	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	SGW	DJ		60	60		38	17	55
103	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	SGW	RC		4,585	4,585		2,910	1,320	4,230
104	Guzman Energy LLC	Black Hills Power	Guzman Energy LLC	NF	8	SHERIDAN	SGW		2,050	2,050		1,301	590	1,891
105	Macquarie Energy LLC	Black Hills Power	Macquarie Energy LLC	NF	8	DJ	RC		1,026	1,026		651	288	939
106	Macquarie Energy LLC	Black Hills Power	Macquarie Energy LLC	NF	8	RC	DJ		110,331	110,331		70,022	30,997	101,019
107	Macquarie Energy LLC	Black Hills Power	Macquarie Energy LLC	NF	8	RC	SGW		386	386		245	108	353
108	Macquarie Energy LLC	Black Hills Power	Macquarie Energy LLC	NF	8	SGW	DJ		273	273		173	77	250
109	MAG Energy Solutions	Black Hills Power	MAG Energy Solutions	NF	8	DJ	RC		14,366	14,366		9,117	7,162	16,279
110	MAG Energy Solutions	Black Hills Power	MAG Energy Solutions	NF	8	RC	DJ		5,222	5,222		3,314	2,604	5,918
111	Pacifcorp	Black Hills Power	Pacifcorp	NF	8	WYODAK	DJ		115	115		73	45	118
112	Pacifcorp	Black Hills Power	Pacifcorp	NF	8	WYODAK	ANTELOPE		174	174		111	68	179
113	Powerex Corp	Black Hills Power	Powerex Corp	NF	8	DJ	RC		13,816	13,816		8,769	5,288	14,057
114	Powerex Corp	Black Hills Power	Powerex Corp	NF	8	RC	DJ		41,021	41,021		26,035	15,702	41,737
115	Powerex Corp	Black Hills Power	Powerex Corp	NF	8	RC	WYODAK		2,708	2,708		1,719	1,037	2,756
116	Powerex Corp	Black Hills Power	Powerex Corp	NF	8	WYODAK	SGW		19	19		12	7	19
117	Public Service Company of Colorado	Black Hills Power	Public Service Company of Colorado	NF	8	DJ	RC		26,145	26,145		16,593	10,442	27,035
118	Public Service Company of Colorado	Black Hills Power	Public Service Company of Colorado	NF	8	DJ	SGW		660	660		419	264	683
119	Public Service Company of Colorado	Black Hills Power	Public Service Company of Colorado	NF	8	RC	DJ		8,654	8,654		5,492	3,456	8,948
120	Public Service Company of Colorado	Black Hills Power	Public Service Company of Colorado	NF	8	RC	SGW		33,554	33,554		21,296	13,401	34,697
121	Public Service Company of Colorado	Black Hills Power	Public Service Company of Colorado	NF	8	SGW	RC		8,635	8,635		5,480	3,449	8,929
122	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	DJ	RC		20,600	20,600		13,074	6,919	19,993
123	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	DJ	SHERIDAN		170	170		108	57	165
124	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	DRYFORK	SHERIDAN		328	328		208	110	318
125	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	RC	DJ		942	942		598	316	914
126	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	RC	SGW		1,450	1,450		920	487	1,407
127	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	SGW	DJ		324	324		206	109	315
128	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	SGW	RC		4,692	4,692		2,978	1,576	4,554
129	Rainbow Energy Marketing Corporation	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	SGW	SHERIDAN		62	62		39	21	60
130	Shell Energy North America	Black Hills Power	Shell Energy North America	NF	8	DJ	RC		1,297	1,297		823	596	1,419
131	Shell Energy North America	Black Hills Power	Shell Energy North America	NF	8	RC	DJ		2,539	2,539		1,612	1,166	2,778

132	Tenaska Power Services Co	Black Hills Power	Tenaska Power Services Co	NF	8	DJ	RC		695	695		441	354	795
133	Tenaska Power Services Co	Black Hills Power	Tenaska Power Services Co	NF	8	RC	DJ		285	285		181	145	326
134	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	DJ	RC		14,627	14,627		9,283	4,728	14,011
135	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	DJ	SGW		651	651		413	210	623
136	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	RC	DJ		28,489	28,489		18,081	9,208	27,289
137	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	RC	SGW		3,453	3,453		2,191	1,116	3,307
138	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	SGW	DJ		440	440		279	142	421
139	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	SGW	RC		1,140	1,140		724	368	1,092
140	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	WYODAK	SGW		310	310		197	100	297
141	The Energy Authority	Black Hills Power	The Energy Authority	NF	8	WSTAR	DJ		172	172		109	56	165
142	TransAlta Energy Marketing U.S.Inc.	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	NF	8	DJ	RC		6,946	6,946		4,408	3,336	7,744
143	TransAlta Energy Marketing U.S.Inc.	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	NF	8	RC	DJ		7,835	7,835		4,973	3,763	8,736
144	Western Area Power Administration - UGP Marketing	Black Hills Power	Western Area Power Administration - UGP Marketing	NF	8	DJ	RC		99	99		63	56	119
145	Western Area Power Administration - UGP Marketing	Black Hills Power	Western Area Power Administration - UGP Marketing	NF	8	SGW	RC		3	3		2	2	4
146	Western Area Power Administration - Rocky Mountain Region	Black Hills Power	Western Area Power Administration - Rocky Mountain Region	NF	8	SGW	RC		4	4		3	3	6
147	Western Area Power Administration - Rocky Mountain Region	Black Hills Power	Western Area Power Administration - Rocky Mountain Region	NF	8	SGW	WYODAK		1	1		1	1	2
148	Municipal Energy Agency of Nebraska (MEAN)	Black Hills Power	Municipal Energy Agency of Nebraska	NF	8	DJ	WSTAR		9	9		6	6	12
149	MFT Energy US Power LLC	Black Hills Power	MFT Energy US Power LLC	NF	8	DJ	RC		616	616		391	64	455
150	Western Area Power Administration - Loveland Area Project	Black Hills Power	Western Area Power Administration - Loveland Area Project	NF	8	DRYFORK	DJ		290	290		184	30	214
151	WestConnect	Black Hills Power	Altop Energy	NF	8	DJ	RC		179	179		152	147	299
152	WestConnect	Black Hills Power	Altop Energy	NF	8	RC	SGW		90	90		76	74	150
153	WestConnect	Black Hills Power	Black Hills Power	NF	8	DJ	RC		80	80		42	72	114
154	WestConnect	Black Hills Power	Black Hills Power	NF	8	SGW	RC		105	105		56	94	150
155	WestConnect	Black Hills Power	Dynasty Power Inc.	NF	8	DJ	RC		560	560		423	282	705
156	WestConnect	Black Hills Power	Dynasty Power Inc.	NF	8	DJ	SGW		120	120		91	60	151
157	WestConnect	Black Hills Power	Dynasty Power Inc.	NF	8	RC	DJ		669	669		505	337	842
158	WestConnect	Black Hills Power	Dynasty Power Inc.	NF	8	RC	SGW		3,280	3,280		2,477	1,650	4,127
159	WestConnect	Black Hills Power	Dynasty Power Inc.	NF	8	SGW	RC		1,165	1,165		880	586	1,466
160	WestConnect	Black Hills Power	Guzman Energy LLC	NF	8	DJ	RC		155	155		112	64	176
161	WestConnect	Black Hills Power	Guzman Energy LLC	NF	8	DJ	SGW		15	15		11	6	17
162	WestConnect	Black Hills Power	Guzman Energy LLC	NF	8	RC	DJ		150	150		109	62	171
163	WestConnect	Black Hills Power	Guzman Energy LLC	NF	8	RC	SGW		140	140		102	58	160
164	WestConnect	Black Hills Power	Guzman Energy LLC	NF	8	SGW	DJ		955	955		692	395	1,087
165	WestConnect	Black Hills Power	Guzman Energy LLC	NF	8	SGW	RC		30	30		22	12	34
166	WestConnect	Black Hills Power	MAG Energy Solutions	NF	8	DJ	RC		1,010	1,010		843	1,050	1,893
167	WestConnect	Black Hills Power	MAG Energy Solutions	NF	8	RC	DJ		33	33		28	34	62
168	WestConnect	Black Hills Power	MAG Energy Solutions	NF	8	RC	SGW		30	30		25	31	56
169	WestConnect	Black Hills Power	MAG Energy Solutions	NF	8	SGW	RC		84	84		70	87	157
170	WestConnect	Black Hills Power	Powerex Corp	NF	8	DJ	SGW		75	75		93	22	115
171	WestConnect	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	DJ	RC		102	102		69	79	148
172	WestConnect	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	RC	DJ		65	65		44	50	94
173	WestConnect	Black Hills Power	Rainbow Energy Marketing Corporation	NF	8	SGW	RC		82	82		55	63	118
174	WestConnect	Black Hills Power	Shell Energy North America	NF	8	DJ	RC		1,150	1,150		973	779	1,752
175	WestConnect	Black Hills Power	Shell Energy North America	NF	8	RC	DJ		256	256		217	173	390
176	WestConnect	Black Hills Power	Shell Energy North America	NF	8	RC	SGW		161	161		136	109	245
177	WestConnect	Black Hills Power	Shell Energy North America	NF	8	SGW	RC		300	300		254	203	457
178	WestConnect	Black Hills Power	The Energy Authority	NF	8	DJ	RC		1,288	1,288		1,115	594	1,709
179	WestConnect	Black Hills Power	The Energy Authority	NF	8	RC	DJ		4,859	4,859		4,207	2,241	6,448

180	WestConnect	Black Hills Power	The Energy Authority	NF	8	RC	SGW		5,668	5,668		4,907	2,614	7,521
181	WestConnect	Black Hills Power	The Energy Authority	NF	8	SGW	RC		2,035	2,035			1,762	2,701
182	WestConnect	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	NF	8	DJ	RC		457	457			345	406
183	WestConnect	Black Hills Power	TransAlta Energy Marketing U.S.Inc.	NF	8	RC	DJ		150	150			113	246
184	^{(b)(5)} Black Hills Power			AD									(860,058)	(860,058)
185	Basin Electric Power			AD									(522,748)	(522,748)
186	City of Gillette			AD									(89,976)	(89,976)
187	State of South Dakota			AD									(5,681)	(5,681)
188	^{(b)(5)} Cheyenne Light, Fuel and Power			AD									146,743	146,743
189	Basin Electric Power			AD									150,599	150,599
190	Municipal Energy Agency of Nebraska (MEAN)			AD									(80,963)	(80,963)
191	^{(b)(5)} Black Hills Wyoming			AD									22,132	22,132
192	^{(b)(5)} Black Hills Colorado Electric			AD									(5)	(5)
193	Altop Energy Trading			AD									(44)	(44)
194	Berkshire Powertech Inc.			AD									(72,592)	(72,592)
195	Dynasty Power Inc.			AD									(206)	(206)
196	Guzman Energy LLC			AD									(2,689)	(2,689)
197	MAG Energy Solutions			AD									(1,052)	(1,052)
198	Macquarie Energy LLC			AD									(7,289)	(7,289)
199	Pacificorp			AD									(5,191)	(5,191)
200	Xcel Energy			AD									(6,075)	(6,075)
201	Powerex Corp			AD									(3,583)	(3,583)
202	Rainbow Energy Marketing Corporation			AD									(1,225)	(1,225)
203	Shell Energy North America			AD									(282)	(282)
204	The Energy Authority			AD									(1,393)	(1,393)
205	TEC Energy Inc.			AD									(36)	(36)
206	TransAlta Energy Marketing U.S.Inc.			AD									(1,840)	(1,840)
207	Tenaska Power Services Co			AD									(299)	(299)
35	TOTAL								7,223,581	7,223,581	13,463,556	22,167,083	^{(b)(5)} 5,294,224	40,924,863

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: 12/31/2025	Year/Period of Report End of: 2025/ 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
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(ah) Concept: PaymentByCompanyOrPublicAuthority
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(ai) Concept: PaymentByCompanyOrPublicAuthority
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(aj) Concept: PaymentByCompanyOrPublicAuthority
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(ak) Concept: PaymentByCompanyOrPublicAuthority
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(al) Concept: PaymentByCompanyOrPublicAuthority
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(am) Concept: PaymentByCompanyOrPublicAuthority
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(an) Concept: PaymentByCompanyOrPublicAuthority
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(ao) Concept: PaymentByCompanyOrPublicAuthority
Affiliate transaction
(ap) Concept: PaymentByCompanyOrPublicAuthority
Affiliate transaction
(aq) Concept: PaymentByCompanyOrPublicAuthority
Affiliate transaction
(ar) Concept: PaymentByCompanyOrPublicAuthority
Affiliate transaction
(as) Concept: TransmissionOfElectricityForOthersEnergyReceived
Losses received on RC DC Tie
(at) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Losses received on RC DC Tie
(au) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Ancillary charges

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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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	2,001	2,001				
2	Pacificorp	FNS	314,482	314,482				
3	Pacificorp	NF	2,367,393	2,367,393				
4	Basin Electric	NF	104,156	104,156		156,075		156,075
5	Colorado River Storage	NF	5,249	5,249		11,833		11,833
6	Northwestern Energy	SFP	190	190		1,161		1,161
7	Public Service Company of Colorado	NF	1,594	1,594		16,258		16,258
8	Southwest Power Pool	NF	106,418	106,418		1,124,117		1,124,117
9	Tucson Electric	NF	90	90		431		431
10	Tri-State Generation	NF	40	40		615		615
11	Western Area Power Administration - Western Area Lower Colorado (WALC)	NF	40	40		97		97
12	Western Area Power Loveland	NF	22,215	22,215		2,306,528		2,306,528
13	Western Area Power Administration	OS				274,660		274,660
14	^(b) Black Hills Basin Electric - Common Use System	LFP	76,901	76,901	2,534,567			2,534,567
15	Transmission Accruals	OS				(1,310,587)		(1,310,587)
16	Western Area Power Administration	OS					2,134,856	2,134,856
17	^(b) Black Hills Basin Electric - Common Use System	FNS	2,018,252	2,018,252		16,126,019	1,096,584	17,222,603
18	^(b) Black Hills Basin Electric - Common Use System	NF	723,536	723,536		723,536	670,989	1,394,525
19	^(b) Black Hills Basin Electric - Common Use System	NF				2,660	154	2,814
	TOTAL		5,742,557	5,742,557	2,534,567	19,433,403	3,902,583	25,870,553

(a) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Affiliate transaction - Black Hills Power (BHP) is a joint owner of the Black Hills Basin Electric (BHBE) Transmission System.

(b) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Affiliate transaction - Black Hills Power (BHP) is a joint owner of the Black Hills Basin Electric (BHBE) Transmission System.

(c) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Affiliate transaction - Black Hills Power (BHP) is a joint owner of the Black Hills Basin Electric (BHBE) Transmission System.

(d) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Affiliate transaction - Black Hills Power (BHP) is a joint owner of the Black Hills Basin Electric (BHBE) Transmission System.

(e) Concept: DemandChargesTransmissionOfElectricityByOthers

Rapid City DC Tie transactions

(f) Concept: OtherChargesTransmissionOfElectricityByOthers

Regulation costs paid to Western Area Power Administration (WAPA)

(g) Concept: OtherChargesTransmissionOfElectricityByOthers

Unless otherwise noted on above lines individually, Other Charges represents ancillary charges for Reactive Voltage Support, Scheduling, and FERC Assessments.

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	36,771
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than \$5,000	
6	Directors' Fees	328,315
7	Bank Fees	196,325
8	Travel	17,663
9	Amortization of Deferred Financing Costs	108,848
10	Business Promotions	33,336
11	Consulting Fees	66,632
12	Economic Development Costs	74,860
13	Software Service	16,310
14	Miscellaneous Other	76,907
46	TOTAL	955,967

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

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

A. Summary of Depreciation and Amortization Charges						
Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant	2,932				2,932
2	Steam Production Plant	13,421,229				13,421,229
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
5.1	Solar Production Plant					
5.2	Wind Production Plant	1,999,234	31,627			2,030,861
5.3	Other Renewable Production Plant					
6	Other Production Plant	5,961,680				5,961,680
7	Transmission Plant	6,838,608				6,838,608
8	Distribution Plant	15,757,332				15,757,332
9	Regional Transmission and Market Operation					
9.1	Energy Storage Plant					
10	General Plant	7,722,915		622,589		8,345,504
11	Common Plant-Electric					
12	TOTAL	51,703,930	31,627	622,589		52,358,146

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	Intangible Plant						
13	(303) Miscellaneous Plant	58					
14	SUBTOTAL INTANGIBLE	58					
15	Steam Production Plant						
16	Osage	816	60 years	22%	12.07%		
17	Wyodak	123,276	58 years	13%	2.86%		24 years
18	Neil Simpson II	228,066	60 years	14%	2.9%		28 years
19	Wygen III	143,933	60 years	13%	2.64%		40 years
20	SUBTOTAL STEAM PROD	496,091					
21	Wind Production						
22	Corriedale Wind Farm	49,696	25 years	0%	4%		20 years
23	SUBTOTAL WIND PRODUCTION	49,696					
24	Other Production Plant						
25	Lange CT	33,876	44 years	5%	2.29%		30 years
26	Neil Simpson I CT	36,215	44 years	5%	2.56%		28 years
27	Ben French CT	23,531	44 years	13%	2.61%		14 years
28	Ben French Diesel CT	2,371	45 years	22%	5.06%		7 years
29	Cheyenne Prairie Generating Station	114,296	40 years	4%	2.98%		42 years
30	SUBTOTAL OTHER PROD	210,289					
31	Transmission Plant						
32	(351.3) Communication Equipment	4,949	20 years	0%	5.63%		14 years

33	(352)Structures and Improvements	2,021	50 years	10%	1.83%		40 years
34	(353)Station Equipment	73,292	42 years	5%	2.13%		36 years
35	(354)Towers and Fixtures	865	60 years	20%	1.74%		56 years
36	(355)Poles and Fixtures	116,178	55 years	30%	2.74%		38 years
37	(356)Overhead Conductors and Devices	93,710	60 years	20%	2.05%		45 years
38	(359)Roads & Trails	7	60 years		1.72%		32 years
39	SUBTOTAL TRANSMISSION	291,022					
40	Distribution Plant						
41	(361)Structures and Improvements	2,329	40 years	5%	2.45%		33 years
42	(362)Station Equipment	118,839	45 years	10%	2.27%		34 years
43	(363.3) Communication Equipment	4,590	20 years	0%	5.63%		14 years
44	(364)Poles, Towers & Fixtures	131,199	50 years	70%	3.64%		37 years
45	(365)Overhead Conductor	72,117	50 years	20%	2.26%		39 years
46	(366)Underground Conduit	28,225	37 years	5%	2.81%		33 years
47	(367)Underground Conductors and Devices	95,057	40 years	5%	2.32%		30 years
48	(368)Line Transformers	81,627	36 years	0%	2.41%		27 years
49	(369)Services	44,591	62 years	50%	2.29%		51 years
50	(370)Meters	13,572	21 years	0%	5.23%		18 years
51	(371)Installation on Customer Premises	3,480	30 years	10%	3.22%		22 years
52	(373)Street Lighting	4,276	25 years	15%	3.96%		17 years
53	SUBTOTAL DISTRIBUTION	599,902					
54	General Plant						
55	(390)Structures and Improvements	86,942	40 years	10%	1.67%		32 years
56	(391)Office Furniture and Equipment	10,363	10 years	0%	13.82%		6 years
57	(392)Transportation Equipment	30,364	13 years	10%	3.45%		11 years
58	(393)Stores Equipment	385	20 years	0%	9.32%		5 years
59	(394)Tools, Shop, & Garage Equipment	3,897	25 years	0%	3.33%		17 years
60	(395)Laboratory Equipment	820	25 years	0%	7.46%		13 years
61	(396)Power Operated Equipment	4,339	30 years	20%	1.28%		27 years
62	(397)Communication Equipment	4,129	20 years	0%	5.63%		14 years
63	(397.1) Computer Hardware	3,248	5 years	0%	20%		5 years
64	(397.3) Communication Equipment	3,234	20 years	0%	5.63%		14 years
65	(398)Miscellaneous Equipment	1,633	20 years	0%	5.8%		13 years
66	SUBTOTAL GENERAL	149,354					
67	TOTAL	1,796,412					

FOOTNOTE DATA

(a) Concept: DepreciationAndAmortization

Note: Amounts footnoted are based upon FERC-approved rates

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	2,932	-	-	-	2,932
2	Steam Production Plant	13,421,229	-	-	-	13,421,229
3	Nuclear Production Plant	-	-	-	-	-
4	Hydraulic Production Plant-Conventional	-	-	-	-	-
5	Hydraulic Production Plant-Pumped Storage	-	-	-	-	-
5.1	Solar Production Plant	-	-	-	-	-
5.2	Wind Production Plant	1,999,234	31,627	-	-	2,030,861
5.3	Other Renewable Production Plant	-	-	-	-	-
6	Other Production Plant	5,961,680	-	-	-	5,961,680
7	Transmission Plant	6,480,676	-	-	-	6,480,676
8	Distribution Plant	15,757,332	-	-	-	15,757,332
9	Regional Transmission and Market Operation	-	-	-	-	-
10	General Plant	11,825,318	-	622,589	-	12,447,907
11	Common Plant-Electric	-	-	-	-	-
12	TOTAL	55,448,402	31,627	622,589	-	56,102,617

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	625,532		625,532		Regulatory	928	623,532				
2	Rate Case Expenses/Other		1,237	1,237		Regulatory	928	1,237				
3	Public Utilities Commission Assessments	544,440	197,709	742,149		Regulatory	928,408.1	742,149				
46	TOTAL	1,169,972	198,946	1,368,918	0			1,366,918				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"> 1. Generation <ol style="list-style-type: none"> a. hydroelectric <ol style="list-style-type: none"> i. Recreation fish and wildlife ii. Other hydroelectric b. Fossil-fuel steam c. Internal combustion or gas turbine d. Nuclear e. Solar f. Wind g. Other renewable h. Unconventional generation i. Siting and heat rejection 2. Transmission 	<ol style="list-style-type: none"> a. Overhead b. Underground 3. Distribution 4. Regional Transmission and Market Operation 5. Energy Storage 6. Environment (other than equipment) 7. Other (Classify and include items in excess of \$50,000.) 8. Total Cost Incurred <p>B. Electric, R, D and D Performed Externally:</p> <ol style="list-style-type: none"> 1. Research Support to the electrical Research Council or the Electric Power Research Institute 2. Research Support to Edison Electric Institute 3. Research Support to Nuclear Power Groups 4. Research Support to Others (Classify) 5. Total Cost Incurred
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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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38							

Name of Respondent:
Black Hills Power Inc.

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

Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	4,466,704		4,466,704
4	Transmission	2,075,592		2,075,592
5	Regional Market			
5.1	Energy Storage			
6	Distribution	3,164,262		3,164,262
7	Customer Accounts	772,689		772,689
8	Customer Service and Informational	310,036		310,036
9	Sales	764		764
10	Administrative and General	15,674,907		15,674,907
11	TOTAL Operation (Enter Total of lines 3 thru 10)	26,464,954		26,464,954
12	Maintenance			
13	Production	2,407,774		2,407,774
14	Transmission	86,216		86,216
15	Regional Market			
15.1	Energy Storage			
16	Distribution	1,208,736		1,208,736
17	Administrative and General	49,996		49,996
18	TOTAL Maintenance (Total of lines 13 thru 17)	3,752,722		3,752,722
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	6,874,478		6,874,478
21	Transmission (Enter Total of lines 4 and 14)	2,161,808		2,161,808
22	Regional Market (Enter Total of Lines 5 and 15)			
22.1	Energy Storage (Enter Total of Lines 5.1 and 15.1)			
23	Distribution (Enter Total of lines 6 and 16)	4,372,998		4,372,998
24	Customer Accounts (Transcribe from line 7)	772,689		772,689
25	Customer Service and Informational (Transcribe from line 8)	310,036		310,036
26	Sales (Transcribe from line 9)	764		764
27	Administrative and General (Enter Total of lines 10 and 17)	15,724,903		15,724,903
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	30,217,676		30,217,676
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 Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance	578,511		578,511
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	30,796,187		30,796,187
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	4,771,741		4,771,741
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	4,771,741		4,771,741
72	Plant Removal (By Utility Departments)			
73	Electric Plant	141,595		141,595
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	141,595		141,595
77	Other Accounts (Specify, provide details in footnote):			
78	Customer Accounts Receivable (142)	12,664		12,664
79	Accounts Receivable Third-Party Billing (143)	(186)		(186)
80	Fuel Stock (200)	(200)		(200)
81	Stores Expense Undistributed (163)	800,427		800,427
82	Preliminary Surveys and Investigation Charges (183)	(29,797)		(29,797)
83	Clearing Accounts (184)	3,410,844		3,410,844
84	Accumulated provision for Pensions and Benefits (228.3)	(21,126)		(21,126)
85	Misc Current and Accrued Liabilities (242)	(295,124)		(295,124)
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,877,502		3,877,502
96	TOTAL SALARIES AND WAGES	39,587,025		39,587,025

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: 12/31/2025	Year/Period of Report End of: 2025/ 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.

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	1,775,163	2,080,255	2,678,359	3,423,980
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(288,334)	(1,052,329)	(1,802,212)	(2,550,920)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
46	TOTAL	1,486,829	1,027,926	876,147	873,060

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			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	4,414,152	kW/M	1,025,056	12,795,295	kW/M	2,917,487
2	Reactive Supply and Voltage	4,414,152	kW/M	1,058,275	12,795,295	kW/M	1,215,478
3	Regulation and Frequency Response	5,303	MW	2,134,856			
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other	2018251	MWh	(98,157)		MWh	1,161,259
8	Total (Lines 1 thru 7)	10,851,858		4,120,030	25,590,590		5,294,224

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: 12/31/2025	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnits Charges represent FERC Annual Assessment, WestConnect, and True-ups
(b) Concept: AncillaryServicesPurchasedAmount Charges represent FERC Annual Assessment, WestConnect, and True-ups

Name of Respondent:
Black Hills Power Inc.

This report is:
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Date of Report:
12/31/2025

Year/Period of Report
End of: 2025/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: Common Use System (CUS)									
1	January	934	21	1	298	372	317		12	
2	February	998	20	7	333	370	317			292
3	March	833	31	11	258	312	317			380
4	Total for Quarter 1				889	1,054	951		12	672
5	April	771	2	10	247	286	317			178
6	May	678	12	16	286	297	317			38
7	June	820	20	17	353	297	317			100
8	Total for Quarter 2				886	880	951			316
9	July	905	21	14	319	311	317			202
10	August	885	7	17	379	332	317		26	418
11	September	812	11	16	334	311	317			155
12	Total for Quarter 3				1,032	954	951		26	775
13	October	764	2	16	279	277	317			300
14	November	851	30	18	305	347	317			195
15	December	847	11	12	250	303	317			152
16	Total for Quarter 4				834	927	951			647
17	Total				3,641	3,815	3,804		38	2,410

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									

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)	1,857,970
3	Steam	1,053,402	23	Requirements Sales for Resale (See instruction 4, page 311.)	491,259
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	339,180
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
6.1	Solar		27	Total Energy Losses	280,594
6.2	Wind		27.1	Total Energy Stored	
6.3	Other Renewable		28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	2,969,003
7	Other	571,841			
8	Less Energy for Pumping				
9	Net Generation (Enter Total of lines 3 through 8)	1,625,243			
10	Purchases (other than for Energy Storage)	1,256,760			
10.1	Purchases for Energy Storage				
11	Power Exchanges:				
12	Received	315,233			
13	Delivered	228,233			
14	Net Exchanges (Line 12 minus line 13)	87,000			
15	Transmission For Other (Wheeling)				
16	Received	1,873,870			
17	Delivered	1,873,870			
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)	2,969,003			

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	245,658	32,767	341	20	19
30	February	222,806	36,254	343	18	9
31	March	230,943	60,521	282	6	10
32	April	261,939	61,132	253	4	9
33	May	251,254	50,665	290	12	15
34	June	268,743	60,231	354	20	16
35	July	266,115	65,325	361	9	17
36	August	231,692	48,750	379	7	17
37	September	217,394	63,319	337	11	17
38	October	213,947	59,721	294	3	16
39	November	264,751	65,303	304	30	18
40	December	293,761	35,264	320	13	18
41	Total	2,969,003	639,252			

Steam Electric Generating Plant Statistics

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

Line No.	Item (a)	Plant Name: Ben French Diesel	Plant Name:	Plant Name: Ben French Station	Plant Name:	Plant Name: 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	110.0	72.4		
6	Net Peak Demand on Plant - MW (60 minutes)	10		98		60	39	37	84	57	69		
7	Plant Hours Connected to Load	15		836		6,299	4,762	3,994	7,338	1,102	7,724		
8	Net Continuous Plant Capability (Megawatts)	10		80		60	38	37	80	57	67		
9	When Not Limited by Condenser Water									57	67		
10	When Limited by Condenser Water								80	57	67		
11	Average Number of Employees			2		6	2	3	25	12	11		
12	Net Generation, Exclusive of Plant Use - kWh	(337,467,000)		20,348,884		292,685,737	144,457,180	114,622,000	527,217,000	46,402,000	473,746,000		
13	Cost of Plant: Land and Land Rights			7,554		1,762,974	2,705		117,401		109,191		
14	Structures and Improvements			1,458,009		5,869,603	948,735	372,279	36,637,217	10,986,706	9,102,799		
15	Equipment Costs	2,370,121		22,026,484		108,195,321	31,576,152	35,414,738	191,518,240	132,537,492	114,145,707		
16	Asset Retirement Costs												
17	Total Cost (10-23)	2,370,121		23,492,047		115,827,898	32,527,592	35,787,017	228,272,858	143,524,198	123,357,697		
18	Cost per KW of Installed Capacity (line 17/5) Including	237.012		233.056		1,158.279	813.190	894.675	2,536.365	1,304.765	1,703.600		
19	Production Expenses: Oper, Supv, & Engr	8,744		201,449		562,007	83,523	93,121	322,668	154,716	1,250,980		
20	Fuel	8,008		1,209,330		7,279,939	4,970,973	3,780,760	9,958,775	1,176,195	8,236,500		
21	Coolants and Water (Nuclear Plants Only)												
22	Steam Expenses								580,056	278,323	182,789		
23	Steam From Other Sources												
24	Steam Transferred (Cr)												
25	Electric Expenses	80,125		97,213		721,518	185,071	388,298	434,750	274,813			
26	Misc Steam (or Nuclear) Power Expenses	(82)		(82)			(82)		552,966	317,302	543,191		
27	Rents					740,287	563,477	945,631	1,505,737	2,336,584			
28	Allowances												
29	Maintenance Supervision and Engineering	92		191			108		441,779	176,783	8,791		
30	Maintenance of Structures			12,731					463,780	260,649			
31	Maintenance of Boiler (or reactor) Plant								2,906,713	1,130,729	1,286,405		
32	Maintenance of Electric Plant	96,654		306,279		1,247,530	1,735,703	389,696	1,539,397	1,297,543	159,195		
33	Maintenance of Misc Steam (or Nuclear) Plant								73,229	45,210	41,078		
34	Total Production Expenses	193,541		1,827,111		10,551,281	7,538,773	5,597,506	18,779,850	7,448,847	11,708,929		
35	Expenses per Net kWh			0.0898		0.0360	0.0522	0.0488	0.0356	0.1605	0.0247		
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	^a Natural Gas	Natural Gas	Natural Gas	Coal	Natural Gas	Coal	Natural Gas	^a Coal
37	Fuel Unit	Bbl	McF	Bbl	McF	McF	McF	Tons	McF	Tons	McF	Tons
38	Quantity (Units) of Fuel Burned	136	314,359	357	2,183,113	1,464,072	1,156,912	424,478	39,756	38,440	6,724	340,343
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	132,260	1,080	130,571	1,050	1,080	1,081	8,004	1,081	8,026	1,081	8,010
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	59.02	3.63	191.37	3.34	3.40	3.27	23.46	2.89	19.30	6.80	20.93
41	Average Cost of Fuel per Unit Burned	59.02	3.63	191.37	3.34	3.40	3.27	23.46	2.89	19.30	6.80	24.20
42	Average Cost of Fuel Burned per Million BTU	10.62	3.36	34.90	3.18	3.15	3.02	1.45	2.68	1.83	6.29	1.51
43	Average Cost of Fuel Burned per kWh Net Gen		0.056		0.025	0.034	0.033	0.155	0.106	0.024	8.475	0.017
44	Average BTU per kWh Net Generation		^a 8,390		7,832	10,946	10,911	^a 12,889		^a 13,298		11,509

FOOTNOTE DATA

(a) Concept: PlantKind
BHP's 58% share-PB1 only
(b) Concept: PlantKind
BHP's 52% share only
(c) Concept: PlantKind
BHP's 20% share only
(d) Concept: PlantAverageNumberOfEmployees
Automatic operation
(e) Concept: PlantAverageNumberOfEmployees
Automatic operation
(f) Concept: PlantAverageNumberOfEmployees
Automatic operation
(g) Concept: FuelKind
BHP's 58% share-PB1 only
(h) Concept: FuelKind
BHP's 20% share only
(i) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Composite of both coal and natural gas
(j) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Composite of both coal and natural gas
(k) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Composite of both coal and natural gas

Hydroelectric Generating Plant Statistics

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

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

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	Cost of Plant				
13	Land and Land Rights				
14	Structures and Improvements				
15	Reservoirs, Dams, and Waterways				
16	Water Wheels, Turbines, and Generators				
17	Accessory Electric Equipment				
18	Miscellaneous Powerplant Equipment				
19	Roads, Railroads, and Bridges				
20	Asset Retirement Costs				
21	Total Cost (10-23)				
22	Cost per KW of installed cap (line 21 / 4)				
23	Production Expenses				
24	Operation Supervision and Engineering				
25	Water for Power				
26	Pumped Storage Expenses				
27	Electric Expenses				
28	Misc Pumped Storage Power generation Expenses				
29	Rents				
30	Maintenance Supervision and Engineering				
31	Maintenance of Structures				
32	Maintenance of Reservoirs, Dams, and Waterways				
33	Maintenance of Electric Plant				
34	Maintenance of Misc Pumped Storage Plant				
35	Production Exp Before Pumping Exp (24 thru 34)				
36	Pumping Expenses				
37	Total Production Exp (total 35 and 36)				
38	Expenses per kWh (line 37 / 9)				
39	Expenses per kWh of Generation and Pumping (line 37/(line 9 + line 10))				

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants, pumped storage plants, and renewable plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, renewable, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l))	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
1													

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) and (b) report the name of the energy storage project and location.
3. In column (c), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In column (d) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (c) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In column (e) report MWHs lost during conversion, storage and discharge of energy.
6. In column (f) report the MWHs sold.
7. In column (g), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (h), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (i) and (j), report fuel costs for storage operations associated with self-generated power and other costs associated with self-generated power.
9. In column (l) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Location of the Project (b)	MWHs (c)	MWHs delivered to the grid (d)	MWHs Lost During Conversion, Storage and Discharge of Energy (e)	MWHs Sold (f)	Revenues from Energy Storage Operations (g)	Power Purchased for Storage Operations (555.1) (Dollars) (h)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (i)	Other Costs Associated with Self-Generated Power (Dollars) (j)	Account for Project Costs (k)	Total Project Plant Costs (l)
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35	TOTAL											

ENERGY STORAGE OPERATIONS (Small Plants)

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

Line No.	Name of the Energy Storage Project (a)	Location of the Project (b)	Project Cost (c)	Plant Operating Expenses				
				Operations (Excluding Fuel used in Storage Operations) (d)	Maintenance (e)	Cost of fuel used in storage operations (f)	Account No. 555.1, Power Purchased for Storage Operations (g)	Other Expenses (h)
1								
2								
3								
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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)	(n)
1	Wyodak	Lookout	230.00	230.00	H-Wood	11.03			1	1272 KCM ACSR	9,800	5,853,081	5,862,881				
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 Rapid Tap	230.00	230.00	H-Wood	2.70			1	1272 KCM ACSR		3,568,337	3,568,337				
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		11,865,330	11,865,330				
7	West Hill	Fall River	230.00	230.00	H-Wood	22.75			1	1272 KCM ACSR	17,701	8,989,265	9,006,966				
8	^(b) 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		926,392	926,392				
10	Minnekahta	Osage	230.00	230.00	H-Wood	23.32			1	1272 KCM ACSR	151,235	2,616,496	2,767,731				
11	Lange	Ben French	69.00	69.00	SP-Steel	3.04			^(b) 2	795 KCM ACSR	44,950	4,530,305	4,575,255				
12	^(b) DC Tie West	South Rapid City	230.00	230.00	SP-Steel	4.00			1	1272 KCM ACSR	127,144	630,238	757,382				
13	^(b) 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	24,508,215	26,020,539				
15	Wyodak	Lookout	230.00	230.00	H-Wood	73.26			1	1272 KCM ACSR	(363,504)	29,074,147	28,710,643				
16	Osage	Minnekahta	230.00	230.00	H-Wood	33.94			1	1272 KCM ACSR	96,159	2,785,459	2,881,618				
17	Osage	Wyodak	230.00	230.00	H-Wood	57.46			1	1272 KCM ACSR	162,516	4,762,825	4,925,341				
18	Neil Simpson I	Neil Simpson II	69.00	69.00	SP-Steel	0.80			1	795 KCM ACSR		304,794	304,794				
19	^(b) 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		180,433	180,433				
21	Donkey Creek	Pumpkin Buttes	230.00	230.00	H-Wood	49.75			1	1272 KCM ACSR	1,280,649	10,112,433	11,393,082				
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	13,661,039	15,865,248				
24	^(b) 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	24,770,300	27,237,845				
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			
30	Fall River	Bluffs	230.00	230.00	H-Wood	0.08		1	1272 KCM ACSR						
31	Bluffs	Stegall	230.00	230.00	H-Wood	0.06		1	1272 KCM ACSR						
36	TOTAL					768		34		9,701,230	210,408,696	220,109,926			

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: 12/31/2025	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: TransmissionLineStartPoint
Bluffs Substation was added in 2025 and split Fall River to Stegall into two segments.
(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
Bluffs Substation was added in 2025 and split Fall River to Stegall into two sections
(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 completed 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)
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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 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	69.0	12.47		22.4	1		Fans LTC		22.4
2	Argyle, SD	Distribution	Unattended	69.0	12.47		5.3	1		Fans		5.3
3	Belle Creek, MT	Distribution	Unattended	69.0	24.90		14.0	1		Fans. Regs		14.0
4	Ben French 24 Rapid City, SD	Distribution	Unattended	69.0	24.90		28.0	1		Fans. Regs		28.0
5	Butte Pipeline, Alzada, MT	Distribution	Unattended	69.0	2.40		12.5	2				12.5
6	Cambell St, Rapid City, SD	Distribution	Unattended	69.0	12.47		14.0	1		Fans LTC		14.0
7	Cemetery, Rapid city, SD	Distribution	Unattended	69.0	12.47		28.0	2		Fans LTC		28.0
8	Century, Rapid City, SD	Distribution	Unattended	69.0	12.47		28.0	2		Fans LTC		28.0
9	Cleveland St. Rapid City, SD	Distribution	Unattended	69.0	12.47		22.4	1		Fans LTC		22.4
10	Cross Street, Rapid City, SD	Distribution	Unattended	69.0	12.47		14.0	1		Fans LTC		14.0
11	Colony Substation, Colony, WY	Distribution	Unattended	69.0	24.90		14.0	1		Fans		14.0
12	Custer, SD	Distribution	Unattended	69.0	12.47		10.5	1		Fans. Regs		10.5
13	Custer, SD	Distribution	Unattended	69.0	24.90		10.5	1		Fans. Regs		10.5
14	East Meade, Rapid City, SD	Distribution	Unattended	69.0	12.47		22.4	1		Fans LTC		22.4
15	East North, Rapid City, SD	Distribution	Unattended	69.0	12.47		34.0	2		Fans LTC		34.0
16	Edgemont City, Edgemont, SD	Distribution	Unattended	69.0	12.47		14.0	1		Fans LTC		14.0
17	Fifth Street, Rapid City, SD	Distribution	Unattended	69.0	12.47		22.4	1		Fans LTC		22.4
18	Forty Fourth Street, Rapid City, SD	Distribution	Unattended	69.0	12.47		14.0	1		Fans LTC		14.0
19	Fourth Street, Rapid City, SD	Distribution	Unattended	69.0	4.16		10.5	1		Fans LTC		10.5
20	Hill City, SD	Distribution	Unattended	69.0	24.90		14.0	1		Fans		14.0
21	Hillsview, Spearfish, SD	Distribution	Unattended	69.0	12.47		14.0	1		Fans LTC		14.0
22	Hot Springs, SD	Distribution	Unattended	69.0	12.47		10.5	1		Fans LTC		10.5
23	Lange, Rapid City, SD	Distribution	Unattended	69.0	24.90		34.0	2		Fans Regs LTC		34.0
24	Mall, Rapid City, SD	Distribution	Unattended	69.0	24.90		14.0	1		Fans Regs		14.0
25	Merillat, Rapid City, SD	Distribution	Unattended	69.0	12.47		28.0	2		Fans LTC		28.0
26	Mountain View, Spearfish, SD	Distribution	Unattended	69.0	24.90		14.0	1		Fans Regs		14.0
27	Newcastle, WY	Distribution	Unattended	69.0	4.16		10.5	1		Fans Regs		10.5
28	Neil Simpson ST 4160 East, Gillette, WY	Distribution	Unattended	69.0	4.16		14.0	1		Fans LTC		14.0
29	Neil Simpson 4160 West, Gillette, WY	Distribution	Unattended	69.0	4.16		10.5	1		Fans		10.5
30	Osage, WY Osage City Sub Osage, WY	Distribution	Unattended	69.0	12.47		10.5	1		Fans		10.5
31	Pleasant Valley, Rapid City, SD	Distribution	Unattended	69.0	12.47		22.4	1		Fans LTC		22.4
32	Pluma, Deadwood, SD	Distribution	Unattended	69.0	12.47		24.5	2		Fans LTC		24.5
33	Rapid City South, Rapid City, SD	Distribution	Unattended	69.0	12.47		34.0	2		Fans LTC		34.0
34	Radio Drive Rapid City, SD	Distribution	Unattended	69.0	12.47		34.0	2		Fans LTC		34.0
35	Richmond Hill, Lead, SD	Distribution	Unattended	69.0	12.47		5.0	2				5.0
36	Spearfish City, Spearfish, SD	Distribution	Unattended	69.0	12.47		14.0	1		Fans LTC		14.0
37	Spearfish Park, Spearfish, SD	Distribution	Unattended	69.0	12.47		14.0	1		Fans LTC		14.0
38	Spruce Gulch, Deadwood, SD	Distribution	Unattended	69.0	12.47		14.0	1		Fans LTC		14.0
39	Sturgis, SD	Distribution	Unattended	69.0	12.47		28.0	1		Fans LTC		28.0
40	Sundance Hill, Belle Fourche, SD	Distribution	Unattended	69.0	24.90		10.5	2		Fans Regs		10.5
41	Sundance Hill, Belle Fourche, SD	Distribution	Unattended	69.0	4.16		7.0	1		Fans LTC		7.0
42	Thirty Eight St., Rapid City, SD	Distribution	Unattended	69.0	12.47		14.0	1		Fans LTC		14.0

43	Trojan, Lead, SD	Distribution	Unattended	69.0	12.47		10.5	1		Fans LTC		10.5
44	Upton, WY Upton city Sub Upton, WY	Distribution	Unattended	69.0	2.40		3.1	1		Fans Regs		3.1
45	West Boulevard, Rapid City, SD	Distribution	Unattended	69.0	4.16		10.5	1		Fans LTC		10.5
46	West Hill, Hot Springs, SD	Distribution	Unattended	69.0	12.47		22.4	1		Fans LTC		22.4
47	Whitewood, SD	Distribution	Unattended	69.0	24.90		14.0	1		Fans Regs		14.0
48	Windy Flats, Nemo	Distribution	Unattended	69.0	12.47		7.0	1		Fans		7.0
49	Portable Sub #1, Rapid City, SD	Distribution	Unattended	69.0	24.90		10.0	1		Fans		10.0
50	Portable Sub #2, Rapid City, SD	Distribution	Unattended	69.0	24.90		20.0	1		Fans		20.0
51	Pactola, Rapid City, SD	Distribution	Unattended	69.0	24.90		10.5	1		Fans		10.5
52	Piedmont, Piedmont, SD	Distribution	Unattended	69.0	24.90		14.0	1		Fans, Regs		14.0
53	Ben French Diesels, Rapid City, SD	Transmission	Unattended	4.2	69.00		14.0	1		Fans		14.0
54	Ben French Combustion Turbines, Rapid City, SD	Transmission	Unattended	13.8	69.00		120.0	4		Fans & Pumps		120.0
55	Cambell ST./East Tie, Rapid City, SD	Transmission	Unattended	115.0	69.00		80.0	2		Fans & Pumps		80.0
56	Lange, Rapid City, SD	Transmission	Unattended	230.0	69.00	13.2	250.0	2		Fans & Pumps		250.0
57	Lange CT, Rapid City, SD	Transmission	Unattended	13.8	69.00		75.0	1		Fans		75.0
58	Lookout, Spearfish, SD	Transmission	Unattended	230.0	69.00	13.2	250.0	2		Fans, Pumps, LTC		250.0
59	Neil Simpson 2 Gillette, WY	Transmission	Unattended	13.8	69.00		150.0	1		Fans		150.0
60	Neil Simpson CT #1, Gillette, WY	Transmission	Unattended	13.8	69.00		84.0	1		Fans		84.0
61	Osage 230, Osage WY	Transmission	Unattended	230.0	69.00	13.2	70.0	1		Fans, Pumps, LTC		70.0
62	West Hill Hot Springs, SD	Transmission	Unattended	230.0	69.00	13.2	50.0	1		Fans, Pumps, LTC		50.0
63	Wyodak 69 Sub, Gillette, WY	Transmission	Unattended	230.0	69.00	13.2	100.0	1		Fans, Pumps, LTC		100.0
64	Yellow Creek, Lead, SD	Transmission	Unattended	230.0	69.00	13.2	250.0	2		Fans, Pumps, LTC		250.0
65	Rapid City South, Rapid City, SD	Transmission	Unattended	230.0	69.00		150.0	1		Fans LTC		150.0
66	Rapid City AC_DC_AC Tie Rapid City SD	Transmission	Unattended	230.0	230.00		218.0	4	1	Fans LTC		218.0
67	Minnekahta Substation, Hot Springs, SD	Transmission	Unattended	230.0	69.00	13.2	70.0	1		Fans LTC		70.0
68	Blucksberg, Sturgis, SD	Distribution	Unattended	69.0	24.90		20.0	1		Fans LTC		20.0
69	Sagebrush, Newcastle, WY	Transmission	Unattended	230.0	69.00	13.2	100.0	1		Fans LTC		100.0
70	West Rapid City, Rapid City, SD	Transmission	Unattended	230.0	69.00	13.2	150.0	1		Fans LTC		150.0
71	Red Rock, Rapid City, SD	Distribution	Unattended	69.0	12.47		20.0	1		Fans LTC		20.0
72	Wyoming Refinery, Newcastle, WY	Distribution	Unattended	69.0	4.16		21.0	2		Fans LTC		21.0
74	Total			6,499	2,128	119	3,100	94	1			3,100

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2	^(b) Allocation of direct and indirect costs provided by BHSC	^(b) Black Hills Service Company	^(b) Various	61,925,351
3	^(b) Allocation of Cheyenne Prairie Generating Station costs	Cheyenne Light, Fuel, and Power	^(b) Various	3,545,528
4	Rent expense from Gillette Energy Complex shared facilities agreement	^(b) Cheyenne Light, Fuel, and Power	507.0	342,081
5	Rent expense from Gillette Energy Complex shared facilities agreement	^(b) Black Hills Wyoming	507.0	28,380
6	Costs under spare turbine agreements	Cheyenne Light, Fuel, and Power	550.0	650,627
7	Costs under spare turbine agreements	Black Hills Colorado IPP	550.0	89,659
8	Wygen III ground lease with WRDC	Wyodak Resources Development Corp.	507.0	1,231,628
19				
20	Non-power Goods or Services Provided for Affiliated			
21	^(b) Allocation of Gillette Energy Complex shared facilities costs	^(b) Cheyenne Light, Fuel, and Power	^(b) Various	2,180,611
22	^(b) Allocation of Gillette Energy Complex shared facilities costs	^(b) Black Hills Wyoming	417.1	2,350,394
23	^(b) Allocation of Corriedale Wind Farm costs	Cheyenne Light, Fuel, and Power	^(b) Various	519,785
24	Gillette Energy Complex rent revenue	^(b) Cheyenne Light, Fuel, and Power	454.0	1,531,078
25	Gillette Energy Complex rent revenue	^(b) Black Hills Wyoming	454.0	1,834,195
26	Rent revenue form Horizon Point facility	Black Hills Service Company	454.0	9,325,992
27	Revenue from affiliates under spare turbine agreements	Cheyenne Light, Fuel, and Power	454.0	1,682,652
28	Revenue from affiliates under spare turbine agreements	Black Hills Colorado IPP	417.4	2,451,429
42				

FOOTNOTE DATA

(a) Concept: DescriptionOfNonPowerGoodOrService

	Indirect	Direct	Combined
Customer Service	\$1,331,724	\$734,967	\$2,066,691
Generation Support	90,548	193,005	283,553
Transmission	4,623,618	9,996,223	14,619,841
Generation Dispatch and Power Marketing	1,562,799	(213,181)	1,349,618
General Accounting	2,367,001	275,416	2,642,417
Executive Management	1,541,226	9,667	1,550,893
NERC Compliance	158,555	-	158,555
Regulatory & Governmental Affairs	1,279,987	1,358,849	2,638,836
Environmental Services	108,634	383,068	491,702
Finance & Treasury	1,046,609	92,188	1,138,797
Information Technology	10,713,823	928,382	11,642,205
Safety	203,207	175,537	378,744
Power Delivery Management	843,140	68,514	911,654
Human Resources	1,232,523	108,732	1,341,255
Communications	458,759	5,494	464,253
Generation Plant Operations	19,925	347,354	367,279
Corporate Development	966,213	440,278	1,406,491
Credit & Risk	4,372	-	4,372
Organizational Development & Training	89,787	1,670	91,457
Internal Audit	416,843	4,538	421,381
Supply Chain Management	979,196	1,540,754	2,519,950
Legal	4,937,626	3,997,222	8,934,848
Tax	553,426	3,829	557,255
Marketing & External Affairs	126,057	277,894	403,951
Other miscellaneous	11,275,223	(5,735,870)	5,539,350
TOTAL	\$46,930,821	\$14,994,530	\$61,925,351

(b) Concept: DescriptionOfNonPowerGoodOrService

CPGS Allocation	
Generation Support	\$585,673
Transmission	8,001
General Accounting	641
Environmental Services	18,229
Information Technology	4,715
Power Delivery Management	983
Generation Plant Operations	2,186,163
Other Miscellaneous	741,123
TOTAL	\$3,545,528

(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: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

	Indirect	Direct	Combined
Operating Revenues (400)	\$(25,392)	\$(17,798)	\$(43,190)
Operation Expenses (401)	36,497,272	8,093,842	44,591,114
Maintenance Expenses (402)	3,703,099	5,672,426	9,375,525
Depreciation Expenses (403)	4,483,776	9,821	4,493,597
Amort & Depl of Utility Plant (404-405)	633,171	-	633,171
Taxes Other than Income Taxes (408.1)	1,125,159	114,993	1,240,152
Revenues from Merchandising, Jobbing, and Contract Work (415)	(28,328)	-	(28,328)
Costs and Exp. of Merchandising, Job, and Contract Work (416)	15,773	19,294	35,067
Expenses of Nonutility Operations (417.1)	12,438	4,863	17,301
Miscellaneous Nonoperating Income (421)	(56,828)	(20,105)	(76,933)
Donations (426.1)	69,572	74,859	144,431
Exp. for Certain Civic, Political & Related Activities (426.4)	87,237	176,637	263,874
Other Deductions (426.5)	412,541	865,240	1,277,781
Taxes Other than Income Taxes (408.2)	1,331	458	1,789
TOTAL	\$46,930,821	\$14,994,530	\$61,925,351
Revenues	\$(110,548)	\$(37,903)	\$(148,451)
Expenses	47,041,369	15,032,433	62,073,802
TOTAL	\$46,930,821	\$14,994,530	\$61,925,351

(g) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

CPGS Allocation	
Operation Expenses (401)	\$2,217,845
Maintenance Expenses (402)	1,250,060
Taxes Other than Income Taxes (408.1)	77,623
TOTAL	\$3,545,528
Revenues	\$-
Expenses	3,545,528
TOTAL	\$3,545,528

(h) Concept: DescriptionOfNonPowerGoodOrService

NSC Allocation to CLFP	
Generation Support	\$1,372,885
General Accounting	78
Environmental Services	22,063
Information Technology	5,322
Power Delivery Management	2,006
Human Resources	1,939
Generation Plant Operations	772,272
Legal	1,335

Other Miscellaneous	2,712
TOTAL	\$2,180,612

(j) Concept: DescriptionOfNonPowerGoodOrService

NSC Allocation to BHW	
Generation Support	\$1,431,012
General Accounting	107
Environmental Services	30,574
Information Technology	7,588
Power Delivery Management	2,915
Human Resources	2,654
Generation Plant Operations	871,101
Legal	1,827
Other Miscellaneous	2,615
TOTAL	\$2,350,393

(j) Concept: DescriptionOfNonPowerGoodOrService

Corriedale Allocation to CLFP	
Generation Support	\$34,182
Transmission	73
General Accounting	151
Environmental Services	2,012
Power Delivery Management	370
Generation Plant Operations	448,070
Legal	34,927
TOTAL	\$519,785

(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.

(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.

(m) 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.

(n) 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.

(o) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

NSC Allocation to CLFP	
Operation Expenses (401)	\$1,029,747
Maintenance Expenses (402)	1,099,843
Taxes Other than Income Taxes (408.1)	50,892
Donations (426.1)	129
TOTAL	\$2,180,611
Revenues	\$-
Expenses	2,180,611
TOTAL	\$2,180,611

(p) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Corriedale Allocation to CLFP	
Operation Expenses (401)	\$517,765
Taxes Other than Income Taxes (408.1)	2,020
TOTAL	\$519,785
Revenues	\$-
Expenses	519,785
TOTAL	\$519,785