

Connie Aschenbrenner
Director of Regulatory Affairs
caschenbrenner@idahopower.com

RECEIVED
April 16, 2026
IDAHO PUBLIC
UTILITIES COMMISSION

April 16, 2026

VIA ELECTRONIC FILING

Commission Secretary
Idaho Public Utilities Commission
11331 W. Chinden Blvd., Bldg 8,
Suite 201-A (83714)
PO Box 83720
Boise, Idaho 83720-0074

Re: Idaho Power Company's 2025 Annual FERC Form 1 Report

Dear Commission Secretary:

Pursuant to Idaho Code § 61-405, attached for electronic filing are Idaho Power Company's FERC Form 1 Report and Idaho Supplement for the year ending December 31, 2025. Also included is the IDACORP 2025 Annual Report.

If you have any questions, please contact Regulatory Consultant Kelley Noe at 208-388-5736 or knoe@idahopower.com.

Sincerely,



Connie Aschenbrenner

CA:sg
Enclosures

THIS FILING IS

Item 1: An Initial (Original) Submission OR Resubmission No.

RECEIVED
April 16, 2026
IDAHO PUBLIC
UTILITIES COMMISSION



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)

Idaho Power Company

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

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

The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings. Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders.

Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at: Secretary Federal Energy Regulatory Commission 888 First Street, NE Washington, DC 20426 For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984).

The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should: Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U.

S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.

) Schedules Pages Comparative Balance Sheet 110-113 Statement of Income 114-117 Statement of Retained Earnings 118-119 Statement of Cash Flows 120-121 Notes to Financial Statements 122-123 The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied.

Insert parenthetical phrases only when exceptions are reported. "In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No.

1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

" The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist. Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling.

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

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

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

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

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

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

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff.

For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

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

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

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

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

DEFINITIONS

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

EXCERPTS FROM THE LAW

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

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

3. 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;
4. 'Person' means an individual or a corporation;

Further instructions are found on the Commission's website at <https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online>.

Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from <https://www.ferc.gov/general-information-0/electric-industry-forms>.

IV. When to Submit

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

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

- V. Where to Send Comments on Public Reporting Burden. The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission).

No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

- I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USoFA). Interpret all accounting words and phrases in accordance with the USoFA.
- II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support.
When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.
- III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.
- IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.
- V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).
- VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.
- VII. For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

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

5. 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;
7. 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power;
11. "project" means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

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

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

"Sec. 304.

- a. Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act.

The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information.

The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy.

The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act.

Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field...

GENERAL PENALTIES

The Commission may assess up to \$1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

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

IDENTIFICATION

01 Exact Legal Name of Respondent Idaho Power Company		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) 1221 W Idaho St, P.O. Box 70 Boise, Id 83707-0070		
05 Name of Contact Person Amy Shaw		06 Title of Contact Person VP of Finance, Compliance and Risk
07 Address of Contact Person (Street, City, State, Zip Code) 1221 W Idaho St, P.O. Box 70 Boise, Id 83707-0070		
08 Telephone of Contact Person, Including Area Code (208) 388-5611	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) 04/13/2026

Annual Corporate Officer Certification

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Amy Shaw	03 Signature Amy Shaw	04 Date Signed (Mo, Da, Yr) 04/13/2026
02 Title VP of Finance, Compliance and Risk		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

LIST OF SCHEDULES (Electric Utility)

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

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	
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	NA
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	NA
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	
22	Materials and Supplies	227	
23	Allowances and Environmental Credits	228	
24	Extraordinary Property Losses	230a	NA
25	Unrecovered Plant and Regulatory Study Costs	230b	NA
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	
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	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	NA
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	NA
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	NA
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	
55	Distribution of Salaries and Wages	354	
56	Common Utility Plant and Expenses	356	NA
57	Amounts included in ISO/RTO Settlement Statements	397	NA
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	NA
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	NA
64	Hydroelectric Generating Plant Statistics	406	

65	Pumped Storage Generating Plant Statistics	408	NA
66	Generating Plant Statistics Pages	410	
66.1	Energy Storage Operations (Large Plants)	414	
66.2	Energy Storage Operations (Small Plants)	419	
67	Transmission Line Statistics Pages	422	
68	Transmission Lines Added During Year	424	
69	Substations	426	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: <input type="checkbox"/> Two copies will be submitted <input checked="" type="checkbox"/> No annual report to stockholders is prepared		

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
GENERAL INFORMATION			
<p>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.</p> <p>Amy Shaw, VP of Finance, Compliance, and Risk, Idaho Power Company 1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070</p> <p>VP of Finance, Compliance, and Risk</p> <p>1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070</p>			
<p>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.</p> <p>State of Incorporation: ID</p> <p>Date of Incorporation: 1989-06-30</p> <p>Incorporated Under Special Law:</p>			
<p>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.</p> <p>Not applicable</p> <p>(a) Name of Receiver or Trustee Holding Property of the Respondent:</p> <p>(b) Date Receiver took Possession of Respondent Property:</p> <p>(c) Authority by which the Receivership or Trusteeship was created:</p> <p>(d) Date when possession by receiver or trustee ceased:</p>			
<p>4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.</p> <p>Class of Utility Service State Electric Idaho Electric Oregon</p>			
<p>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?</p> <p>(1) <input type="checkbox"/> Yes</p> <p>(2) <input checked="" type="checkbox"/> No</p>			

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
CONTROL OVER RESPONDENT			
<p>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.</p>			
<p>IDACORP owns 100% of Idaho Power Company's Common Stock. IDACORP is a public utility Holding Company Incorporated effective October 1, 1998.</p>			

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

CORPORATIONS CONTROLLED BY RESPONDENT

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

Definitions

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Direct Control			
2	Idaho Energy Resources Company	Coal mining and mineral	100%	
3		development		

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

OFFICERS

- 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.
- 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 CEO	Lisa A. Grow	1,050,000		
2	(g) Executive Vice President, COO	Adam J. Richins	620,000		
3	(h) Executive Vice President, CFO, and Treasurer	Brian R. Buckham	600,000		
4	Senior Vice President, Public Affairs	Jeffery L. Malmen	453,000		
5	Vice President, Regulatory Affairs	Tim E. Tatum	360,000		
6	Vice President, Power Supply	Ryan N. Adelman	350,000		
7	Vice President, Human Resources	Sarah E. Griffin	340,000		
8	Vice President, Customer Operations and CSO	Bo D. Hanchey	302,000		
9	(g) Vice President	Debra H. Leithauser	281,500		2025-10-31
10	Vice President, Information Technology and CIO	Jason C. Huszar	340,000		
11	Vice President, Planning, Engineering, and Construction	Mitch Colburn	340,000		
12	Vice President, General Counsel	Julia A. Hilton	350,000		
13	Vice President, Finance, Compliance, and Risk	Amy I. Shaw	265,000		
14	(d) Vice President, Corporate Services and Communications	Angelique R. Rood	240,000	2025-02-01	
15	Corporate Secretary	Cheryl W. Thompson	250,000		

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: OfficerTitle
Title change to Executive Vice President, COO effective 2/12/26, previous title was Senior Vice President, COO.
(b) Concept: OfficerTitle
Title change to Executive Vice President, CFO, and Treasurer effective 2/12/26, previous title was Senior Vice President, CFO, and Treasurer.
(c) Concept: OfficerTitle
Title change to Vice President effective 2/13/25, previous title was Vice President, Corporate Services and Communications.
(d) Concept: OfficerTitle
Title change to Vice President, Corporate Services and Communications effective 2/1/25, previous title was Regional Manager.

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Odette C. Bolano	1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070	false	false
2	Annette G. Elg, Audit Chair	1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070	true	false
3	Lisa A. Grow, President and CEO, Exec. Chair	1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070	true	true
4	(a) Ronald W. Jibson	1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070	false	false
5	(b) Judith A. Johansen, Comp. & HR Chair	1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070	true	false
6	Dennis L. Johnson, Board Chair, Corp. Gov. & Nominating Chair	1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070	true	false
7	Nate R. Jorgensen	1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070	false	false
8	(c) Michael J. Kennedy	1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070	false	false
9	(d) Scott W. Madison	1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070	false	false
10	Susan D. Morris	250 E. Parkcenter Blvd, Boise, ID 83706	false	false
11	(e) Richard J. Navarro	1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070	false	false
12	Dr. Mark T. Peters	7525 Colshire Drive, McLean, VA 22102	false	false

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

<u>(a)</u> Concept: NameAndTitleOfDirector Ronald Jibson retired from the Board on May 15, 2025.
<u>(b)</u> Concept: NameAndTitleOfDirector Judith Johansen retired from the Board on December 31, 2025.
<u>(c)</u> Concept: NameAndTitleOfDirector Michael Kennedy was appointed to the Board on May 15, 2025.
<u>(d)</u> Concept: NameAndTitleOfDirector Scott Madison was elected to the Board on February 13, 2025.
<u>(e)</u> Concept: NameAndTitleOfDirector Richard Navarro retired from the Board on May 15, 2025.

Name of Respondent: Idaho Power Company		This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
INFORMATION ON FORMULA RATES					
Does the respondent have formula rates?				<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	
1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.					
Line No.	FERC Rate Schedule or Tariff Number (a)			FERC Proceeding (b)	
1	Idaho Power's OATT, Attachment H, Section 2.1			ER09-1641-000	

Name of Respondent: Idaho Power Company		This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding					
Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?			<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No		
2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website.					
Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	Accession No. 20250905-5174	09/05/2025	ER09-1641-000	Amended Informational Filing of 2025-2026 Formula Rate Annual Update of Idaho Power Company under ER25-3346, et al.	FERC Electric Tariff
2	Accession No. 20250828-5279	08/28/2025	ER09-1641-000	Informational Filing of 2025-2026 Formula Rate Annual Update of Idaho Power Company under ER25-3346, et al.	FERC Electric Tariff
3	Accession No. 20240828-5195	08/28/2024	ER09-1641-000	Informational Filing of 2024-2025 Formula Rate Annual Update of Idaho Power Company under ER24-2934, et al.	FERC Electric Tariff

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

INFORMATION ON FORMULA RATES - Formula Rate Variances

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

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				

31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

1.) None.

2.) None.

3.) None.

4.) Idaho Power Company has a 20-year Energy Storage Agreement with Kuna BESS, which developed, designed, constructed, owns and operates a battery energy storage system on a site located in Kuna, Idaho, with a commercial operation date of May 19, 2025. Idaho Power Company is responsible for providing the energy to charge the project, which has a maximum effective capacity of 150 megawatts (MW), and effective energy capacity of 600 megawatt-hour (MWh). Idaho Power Company pays Kuna BESS monthly, a contract price of \$11,970/MW-month multiplied by the then-applicable effective capacity, net of monthly capacity payment adjustments. The energy storage agreement is considered a lease for accounting purposes and was approved by the Idaho Public Utilities Commission on Order No. 36011 and Order No. 36016 on November 27 and December 1, 2023, respectively.

5.) None.

6.) On March 13, 2025, Idaho Power issued \$400 million in aggregate principal amount of 5.70% first mortgage bonds, secured medium-term notes, Series O, maturing on March 15, 2055. Idaho Power's issuance of long-term indebtedness is subject to the approval of the IPUC, OPUC, and WPSC. In February and March 2024, Idaho Power received orders from the IPUC, OPUC, and WPSC authorizing the company to issue and sell from time to time up to \$1.2 billion in aggregate principal amount of debt securities and first mortgage bonds, subject to conditions specified in the orders. Authority from the IPUC is effective through December 31, 2026, subject to extensions upon request to the IPUC. The OPUC's and WPSC's orders do not impose a time limitation for issuances, but the OPUC order does impose a number of other conditions, including a requirement that the interest rates for the debt securities or first mortgage bonds fall within either (a) designated spreads over comparable U.S. Treasury rates or (b) a maximum interest rate limit of 8 percent. At December 31, 2025, \$500 million remained available for debt issuance under the regulatory orders.

7.) None.

8.) Effective 12/20/2025, a 3.5% general wage adjustment was implemented.

9.) None.

10.) None.

12.) None.

13.)
Officer Changes in 2025 and 2026 to date:
On February 13, 2025, Angelique Rood became Vice President of Corporate Services and Communications.
Effective October 31, 2025, Debra Leithauser retired from the company as Vice President.
Brian Buckham became Executive Vice President, CFO, and Treasurer effective February 12, 2026. His previous title was Senior Vice President, CFO, and Treasurer.
Adam Richins became Executive Vice President and COO effective February 12, 2026. His previous title was Senior Vice President and COO.
Director Changes in 2025:
Scott Madison was appointed to the Board on February 13, 2025.
Mike Kennedy was elected to the Board on May 15, 2025.
Rick Navarro and Ron Jibson retired from the Board on May 15, 2025.
Judi Johansen retired from the Board effective December 31, 2025.

14.) Not applicable.

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200	8,496,770,991	7,975,277,159
3	Construction Work in Progress (107)	200	1,743,553,102	1,245,682,478
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		10,240,324,093	9,220,959,637
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	2,763,239,071	2,881,559,900
6	Net Utility Plant (Enter Total of line 4 less 5)		7,477,085,022	6,339,399,737
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)		7,477,085,022	6,339,399,737
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		7,161,400	5,104,706
19	(Less) Accum. Prov. for Depr. and Amort. (122)		446,271	246,891
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224	26,625,321	24,376,687
23	Noncurrent Portion of Allowances and Environmental Credits	228		
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		74,032,066	73,598,796
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	0

32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		107,372,516	102,833,298
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		8,071,143	29,492,757
36	Special Deposits (132-134)		17,736,672	9,451,107
37	Working Fund (135)		39,000	39,000
38	Temporary Cash Investments (136)		110,601,801	158,998,549
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		101,497,412	119,894,558
41	Other Accounts Receivable (143)		19,731,701	19,347,044
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		4,424,709	5,698,918
43	Notes Receivable from Associated Companies (145)		14,400,935	14,844,151
44	Accounts Receivable from Assoc. Companies (146)		0	0
45	Fuel Stock (151)	227	24,454,598	43,656,474
46	Fuel Stock Expenses Undistributed (152)	227		0
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	185,433,463	180,642,850
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		0
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances and Environmental Credits (158.1, 158.2, 158.3, and 158.4)	228	1,359,888	
53	(Less) Noncurrent Portion of Allowances and Environmental Credits	228		
54	Stores Expense Undistributed (163)	227	16,463,017	20,421,571
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		30,447,248	29,327,675
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)		291,005	704,318
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)		79,931,469	97,710,905
62	Miscellaneous Current and Accrued Assets (174)			
63	Derivative Instrument Assets (175)		3,080	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0

67	Total Current and Accrued Assets (Lines 34 through 66)		606,037,723	718,832,041
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		26,468,992	23,673,395
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	1,564,458,885	1,499,536,713
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,666,637	3,854,932
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)		2,584,241	4,321,900
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	120,171,466	107,130,020
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352	0	0
81	Unamortized Loss on Reaquired Debt (189)		28,852,727	31,289,400
82	Accumulated Deferred Income Taxes (190)	234	327,326,152	310,877,872
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		2,071,529,100	1,980,684,232
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		10,262,024,361	9,141,749,308

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250	97,877,030	97,877,030
3	Preferred Stock Issued (204)	250	0	0
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		1,107,257,435	912,257,435
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b	2,096,925	2,096,925
11	Retained Earnings (215, 215.1, 216)	118	2,199,736,794	2,074,237,215
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	24,162,228	21,913,594
13	(Less) Recquired Capital Stock (217)	250	0	0
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(14,944,476)	(13,592,234)
16	Total Proprietary Capital (lines 2 through 15)		3,411,992,086	3,090,596,115
17	LONG-TERM DEBT			
18	Bonds (221)	256	3,461,300,000	3,061,300,000
19	(Less) Recquired Bonds (222)	256	0	0
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	0	19,885,000
22	Unamortized Premium on Long-Term Debt (225)		24,537,646	25,644,608
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		12,031,086	9,494,002
24	Total Long-Term Debt (lines 18 through 23)		3,473,806,560	3,097,335,606
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		216,694,830	
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		2,941,529	3,569,555
29	Accumulated Provision for Pensions and Benefits (228.3)		138,622,811	166,891,354
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		280,979,311	250,941,227

32	Long-Term Portion of Derivative Instrument Liabilities		13,618,402	11,808,134
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		73,976,051	51,125,600
35	Total Other Noncurrent Liabilities (lines 26 through 34)		726,832,934	484,335,870
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		373,212,434	332,320,831
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		3,555,457	3,403,416
41	Customer Deposits (235)		1,168,647	1,289,475
42	Taxes Accrued (236)	262	6,275,485	(5,057,730)
43	Interest Accrued (237)		51,116,616	46,852,687
44	Dividends Declared (238)		1,509,966	1,202,764
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		834,708	1,341,468
48	Miscellaneous Current and Accrued Liabilities (242)		278,583,944	254,576,153
49	Obligations Under Capital Leases-Current (243)		6,161,227	
50	Derivative Instrument Liabilities (244)		19,719,739	16,259,271
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		13,618,402	11,808,134
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		728,519,821	640,380,201
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		55,239,914	58,546,387
57	Accumulated Deferred Investment Tax Credits (255)	266	235,724,114	230,322,101
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	93,608,420	44,578,395
60	Other Regulatory Liabilities (254)	278	383,878,430	336,880,879
61	Unamortized Gain on Reacquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		1,014,721,465	1,012,593,617
64	Accum. Deferred Income Taxes-Other (283)		137,700,617	146,180,137
65	Total Deferred Credits (lines 56 through 64)		1,920,872,960	1,829,101,516
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		10,262,024,361	9,141,749,308

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)
1	UTILITY OPERATING INCOME						
2	Operating Revenues (400)	300	1,804,403,419	1,818,832,846			1,804,403,419
3	Operating Expenses						
4	Operation Expenses (401)	320	1,034,605,871	1,158,395,810			1,034,605,871
5	Maintenance Expenses (402)	320	138,206,602	95,470,150			138,206,602
6	Depreciation Expense (403)	336	235,309,143	214,756,943			235,309,143
7	Depreciation Expense for Asset Retirement Costs (403.1)	336					
8	Amort. & Depl. of Utility Plant (404-405)	336	11,307,993	7,601,772			11,307,993
9	Amort. of Utility Plant Acq. Adj. (406)	336	15,018	15,018			15,018
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)						
11	Amort. of Conversion Expenses (407.2)						
12	Regulatory Debits (407.3)		5,269,382	5,583,229			5,269,382
13	(Less) Regulatory Credits (407.4)		0	0			0

14	Taxes Other Than Income Taxes (408.1)	262	28,389,737	16,155,738		28,389,737
15	Income Taxes - Federal (409.1)	262	18,645,847	5,421,813		18,645,847
16	Income Taxes - Other (409.1)	262	3,379,772	8,877,729		3,379,772
17	Provision for Deferred Income Taxes (410.1)	234, 272	18,661,774	20,500,102		18,661,774
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	67,814,872	94,796,668		67,814,872
19	Investment Tax Credit Adj. - Net (411.4)	266	45,738,426	94,674,793		45,738,426
20	(Less) Gains from Disp. of Utility Plant (411.6)		824	617		824
21	Losses from Disp. of Utility Plant (411.7)		0	906		0
22	(Less) Gains from Disposition of Allowances (411.8)		0	759,456		0
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		2,119	8,600		2,119
24.1	(Less) Gains from Disposition of Environmental Credits (411.11)		1,656,111			1,656,111
24.2	Losses from Disposition of Environmental Credits (411.12)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24.2)		1,470,059,877	1,531,905,862		1,470,059,877
27	Net Util Oper Inc (Enter Tot line 2 less 25)		334,343,542	286,926,984		334,343,542
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		5,270,113	4,376,138		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		6,638,044	5,418,390		
33	Revenues From Nonutility Operations (417)		10,523	11,878		
34	(Less) Expenses of Nonutility Operations (417.1)		175,118	90,810		
35	Nonoperating Rental Income (418)		6,874	19,407		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	2,248,634	1,651,181		
37	Interest and Dividend Income (419)		35,988,127	39,309,093		

38	Allowance for Other Funds Used During Construction (419.1)		62,488,668	53,238,345		
39	Miscellaneous Nonoperating Income (421)		7,017,427	8,853,147		
40	Gain on Disposition of Property (421.1)		0	801,694		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		106,217,204	102,751,683		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		818,091	537,890		
46	Life Insurance (426.2)		(13,243,729)	(10,186,458)		
47	Penalties (426.3)		60,000	(7,000)		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,470,797	1,528,299		
49	Other Deductions (426.5)		8,281,233	(992,614)		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		(2,613,608)	(9,119,883)		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262	17,987	23,306		
53	Income Taxes-Federal (409.2)	262	6,471,907	9,713,174		
54	Income Taxes-Other (409.2)	262	1,656,028	2,960,983		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	542,877	157,800		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	206,224	346,717		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		40,336,414	29,831,234		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(31,853,839)	(17,322,688)		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		140,684,651	129,194,254		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		166,342,056	139,196,308		
63	Amort. of Debt Disc. and Expense (428)		2,187,739	1,847,044		
64	Amortization of Loss on Reaquired Debt (428.1)		2,436,673	2,700,954		

65	(Less) Amort. of Premium on Debt-Credit (429)		1,106,961	1,106,961			
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)						
67	Interest on Debt to Assoc. Companies (430)		0	0			
68	Other Interest Expense (431)		25,517,469	20,663,920			
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		36,210,633	27,784,737			
70	Net Interest Charges (Total of lines 62 thru 69)		159,166,343	135,516,528			
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		315,861,850	280,604,710			
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)		315,861,850	280,604,710			

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	1,818,832,846				
3	Operating Expenses					
4	Operation Expenses (401)	1,158,395,810				
5	Maintenance Expenses (402)	95,470,150				
6	Depreciation Expense (403)	214,756,943				
7	Depreciation Expense for Asset Retirement Costs (403.1)					
8	Amort. & Depl. of Utility Plant (404-405)	7,601,772				
9	Amort. of Utility Plant Acq. Adj. (406)	15,018				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407.2)					
12	Regulatory Debits (407.3)	5,583,229				
13	(Less) Regulatory Credits (407.4)	0				
14	Taxes Other Than Income Taxes (408.1)	16,155,738				
15	Income Taxes - Federal (409.1)	5,421,813				
16	Income Taxes - Other (409.1)	8,877,729				

17	Provision for Deferred Income Taxes (410.1)	20,500,102			
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	94,796,668			
19	Investment Tax Credit Adj. - Net (411.4)	94,674,793			
20	(Less) Gains from Disp. of Utility Plant (411.6)	617			
21	Losses from Disp. of Utility Plant (411.7)	906			
22	(Less) Gains from Disposition of Allowances (411.8)	759,456			
23	Losses from Disposition of Allowances (411.9)				
24	Accretion Expense (411.10)	8,600			
24.1	(Less) Gains from Disposition of Environmental Credits (411.11)				
24.2	Losses from Disposition of Environmental Credits (411.12)				
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24.2)	1,531,905,862			
27	Net Util Oper Inc (Enter Tot line 2 less 25)	286,926,984			
28	Other Income and Deductions				
29	Other Income				
30	Nonutility Operating Income				
31	Revenues From Merchandising, Jobbing and Contract Work (415)				
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)				
33	Revenues From Nonutility Operations (417)				
34	(Less) Expenses of Nonutility Operations (417.1)				
35	Nonoperating Rental Income (418)				
36	Equity in Earnings of Subsidiary Companies (418.1)				
37	Interest and Dividend Income (419)				
38	Allowance for Other Funds Used During Construction (419.1)				
39	Miscellaneous Nonoperating Income (421)				
40	Gain on Disposition of Property (421.1)				
41	TOTAL Other Income (Enter Total of lines 31 thru 40)				
42	Other Income Deductions				
43	Loss on Disposition of Property (421.2)				

44	Miscellaneous Amortization (425)					
45	Donations (426.1)					
46	Life Insurance (426.2)					
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)					
49	Other Deductions (426.5)					
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)					
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)					
53	Income Taxes-Federal (409.2)					
54	Income Taxes-Other (409.2)					
55	Provision for Deferred Inc. Taxes (410.2)					
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)					
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)					
60	Net Other Income and Deductions (Total of lines 41, 50, 59)					
61	Interest Charges					
62	Interest on Long-Term Debt (427)					
63	Amort. of Debt Disc. and Expense (428)					
64	Amortization of Loss on Reaquired Debt (428.1)					
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)					
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)					
70	Net Interest Charges (Total of lines 62 thru 69)					
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)					
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)					
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)					

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		2,060,964,109	1,957,783,262
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		313,613,216	278,953,528
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Acct 438		(188,113,638)	(175,772,681)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(188,113,638)	(175,772,681)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		0	0
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,186,463,687	2,060,964,109
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			

46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		13,273,107	13,273,106
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		13,273,107	13,273,106
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,199,736,794	2,074,237,215
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		21,913,594	20,262,413
50	Equity in Earnings for Year (Credit) (Account 418.1)		2,248,634	1,651,181
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)		24,162,228	21,913,594

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

STATEMENT OF CASH FLOWS

- 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.
- 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.
- 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.
- 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)	315,861,850	280,604,710
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	235,309,143	214,756,944
5	Amortization of (Specify) (footnote details)		
5.1	Plant	11,323,011	7,616,790
5.2	Unamortized debt expense	4,442,023	4,543,315
5.3	Unamortized discount	(572,045)	(665,359)
5.4	Water Rights	86,834	1,042,009
5.5	Other	199,261	185,925
5.6	Lease right-of-use asset	7,005,657	
8	Deferred Income Taxes (Net)	(41,660,279)	(31,828,514)
9	Investment Tax Credit Adjustment (Net)	(1,137,963)	22,476,074
10	Net (Increase) Decrease in Receivables	(2,017,797)	32,275,578
11	Net (Increase) Decrease in Inventory	18,369,817	(84,260,605)
12	Net (Increase) Decrease in Allowances and Environmental Credits Inventory	806,213	0
13	Net Increase (Decrease) in Payables and Accrued Expenses	(5,312,421)	(13,988,721)
14	Net (Increase) Decrease in Other Regulatory Assets	8,722,736	94,687,797
15	Net Increase (Decrease) in Other Regulatory Liabilities	22,506,391	20,338,052
16	(Less) Allowance for Other Funds Used During Construction	62,488,668	53,238,345
17	(Less) Undistributed Earnings from Subsidiary Companies	1,805,417	2,717,113
18	Other (provide details in footnote):		
18.1	Pension and postretirement benefit plan expense	45,191,616	45,763,968
18.2	Contributions to pension and postretirement benefit plans	(27,588,798)	(25,426,888)
18.3	Changes in company owned life insurance	(13,243,730)	(10,186,458)
18.4	Changes in other	(1,689,875)	(151,987)
18.5	Changes in prepayments		(8,926,946)

18.6	Changes in other liabilities		40,374,020
18.7	Changes in unbilled receivables	10,057,946	
18.8	Changes in other long-term liabilities	45,412,642	
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	567,778,147	561,251,688
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(1,241,478,952)	(1,062,376,776)
27	Gross Additions to Nuclear Fuel	0	0
28	Gross Additions to Common Utility Plant	0	0
29	Gross Additions to Nonutility Plant	0	0
30	(Less) Allowance for Other Funds Used During Construction	(62,488,668)	(53,238,345)
31	Other (provide details in footnote):		
31.1	Payments received from joint funding partners	151,880,303	83,707,672
31.2	Sale of renewable energy certificates and emission allowances	13,151,429	5,331,502
31.3	Sale of utility property		6,115,998
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(1,013,958,552)	(913,983,259)
36	Acquisition of Other Noncurrent Assets (d)	0	0
37	Proceeds from Disposal of Noncurrent Assets (d)	0	0
39	Investments in and Advances to Assoc. and Subsidiary Companies	0	0
40	Contributions and Advances from Assoc. and Subsidiary Companies	0	0
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies	0	0
44	Purchase of Investment Securities (a)	(11,361,092)	(12,960,843)
45	Proceeds from Sales of Investment Securities (a)	12,012,724	10,641,006
46	Loans Made or Purchased	0	0
47	Collections on Loans	0	0
49	Net (Increase) Decrease in Receivables	0	0
50	Net (Increase) Decrease in Inventory	0	0
51	Net (Increase) Decrease in Allowances and Environmental Credits Held for Speculation	0	0
52	Net Increase (Decrease) in Payables and Accrued Expenses	0	0
53	Other (provide details in footnote):		
53.1	Life insurance proceeds received		801,757
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(1,013,306,920)	(915,501,339)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	400,000,000	300,000,000

62	Preferred Stock	0	0
63	Common Stock	0	0
64	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Capital infusion from IDACORP	195,000,000	200,000,000
70	Cash Provided by Outside Sources (Total 61 thru 69)	595,000,000	500,000,000
72	Payments for Retirement of:		
73	Long-term Debt (b)	(19,885,000)	(49,800,000)
74	Preferred Stock	0	0
75	Common Stock	0	0
76	Other (provide details in footnote):		
76.1	Other	⁽⁹⁾ (11,598,153)	⁽⁹⁾ (3,179,721)
78	Net Decrease in Short-Term Debt (c)	0	0
80	Dividends on Preferred Stock	0	0
81	Dividends on Common Stock	(187,806,436)	(175,771,796)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	375,710,411	271,248,483
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)	(69,818,362)	(83,001,168)
88	Cash and Cash Equivalents at Beginning of Period	188,530,306	271,531,474
90	Cash and Cash Equivalents at End of Period	118,711,944	188,530,306

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)
1	Net Cash Flow from Operating Activities
2	Net Income (Line 78(c) on page 117)
3	Noncash Charges (Credits) to Income:
4	Depreciation and Depletion
5	Amortization of (Specify) (footnote details)
5.1	Plant
5.2	Unamortized debt expense
5.3	Unamortized discount
5.4	Water Rights
5.5	Other
5.6	Lease right-of-use asset
8	Deferred Income Taxes (Net)
9	Investment Tax Credit Adjustment (Net)
10	Net (Increase) Decrease in Receivables
11	Net (Increase) Decrease in Inventory
12	Net (Increase) Decrease in Allowances and Environmental Credits Inventory
13	Net Increase (Decrease) in Payables and Accrued Expenses
14	Net (Increase) Decrease in Other Regulatory Assets
15	Net Increase (Decrease) in Other Regulatory Liabilities
16	(Less) Allowance for Other Funds Used During Construction
17	(Less) Undistributed Earnings from Subsidiary Companies
18	Other (provide details in footnote):
18.1	Pension and postretirement benefit plan expense
18.2	Contributions to pension and postretirement benefit plans
18.3	Changes in company owned life insurance
18.4	Changes in other
18.5	Changes in prepayments
18.6	Changes in other liabilities
18.7	Changes in unbilled receivables
18.8	Changes in other long-term liabilities

22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)
24	Cash Flows from Investment Activities:
25	Construction and Acquisition of Plant (including land):
26	Gross Additions to Utility Plant (less nuclear fuel)
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
31	Other (provide details in footnote):
31.1	Payments received from joint funding partners
31.2	Sale of renewable energy certificates and emission allowances
31.3	Sale of utility property
34	Cash Outflows for Plant (Total of lines 26 thru 33)
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	Life insurance proceeds received
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)
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):
66	Net Increase in Short-Term Debt (c)
67	Other (provide details in footnote):
67.1	Capital infusion from IDACORP

70	Cash Provided by Outside Sources (Total 61 thru 69)
72	Payments for Retirement of:
73	Long-term Debt (b)
74	Preferred Stock
75	Common Stock
76	Other (provide details in footnote):
76.1	Other
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)
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)
88	Cash and Cash Equivalents at Beginning of Period
90	Cash and Cash Equivalents at End of Period

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: NetIncreaseDecreaseInPayablesAndAccruedExpensesOperatingActivities

Cash (received) paid during the period for:

Income taxes	20,689,272
Interest (net of amount capitalized)	138,838,969

(b) Concept: GrossAdditionsToUtilityPlantLessNuclearFuelInvestingActivities

Non-cash investing and financing activities:

Additions to PP&E in accounts payable	222,340,155
ROU asset obtained in exchange for capital lease liability	226,617,790

(c) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Other Financing Cash Flows

Discount on debt issuance	(3,072,000)
Payments on lease obligations	(3,761,733)
Debt issuance cost	(4,764,420)
Total	(11,598,153)

(d) Concept: NetIncreaseDecreaseInPayablesAndAccruedExpensesOperatingActivities

Cash (received) paid during the period for:

Income taxes	30,972,044
Interest (net of amount capitalized)	108,717,907

(e) Concept: GrossAdditionsToUtilityPlantLessNuclearFuelInvestingActivities

Non-cash investing activities:

Additions to PP&E in accounts payable	168,106,954
---------------------------------------	-------------

(f) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

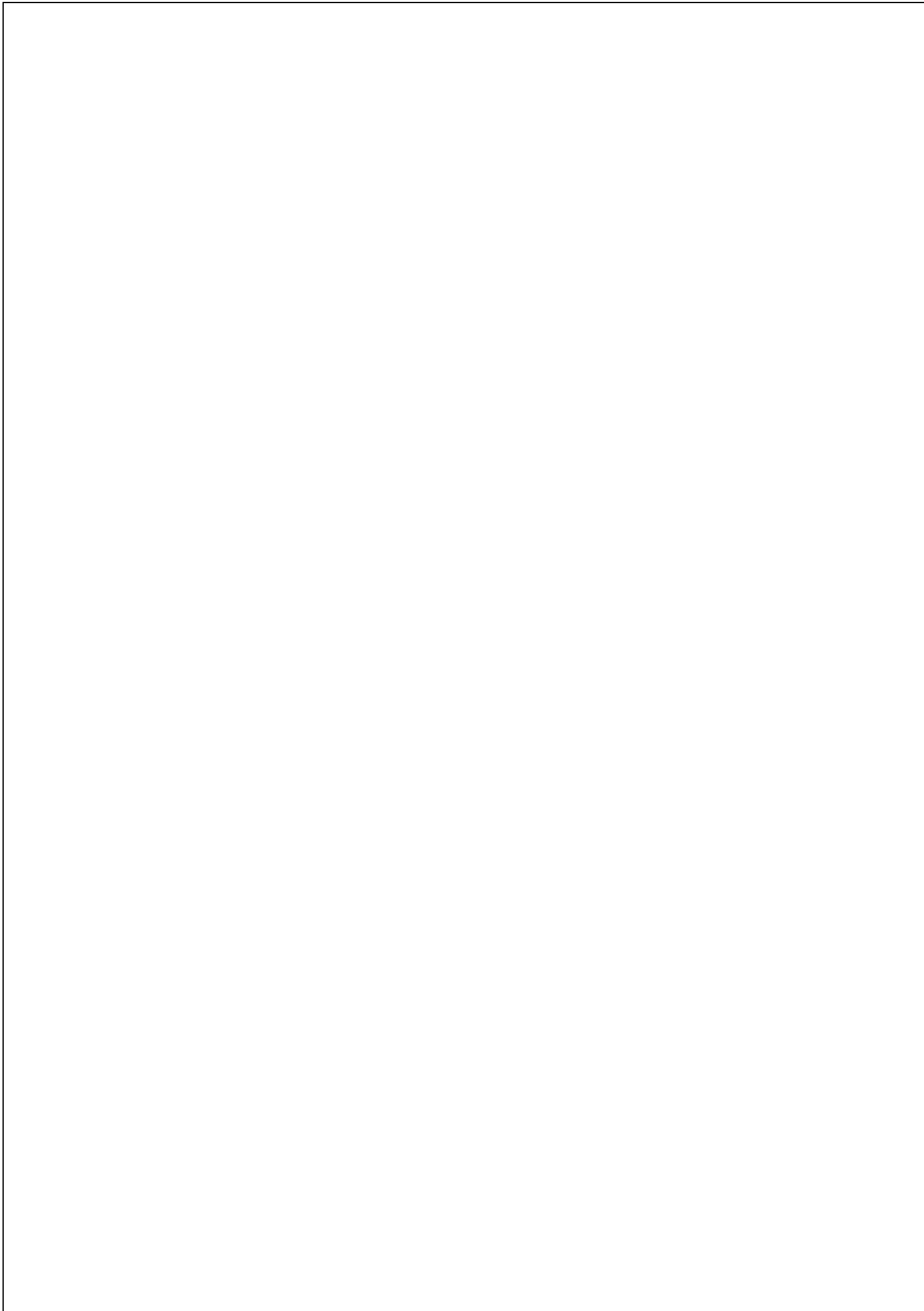
Other Financing Cash Flows

Discount on debt issuance	(186,000)
Debt issuance cost	(2,993,721)
Total	(3,179,721)

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

NOTES TO FINANCIAL STATEMENTS

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



NOTES TO FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Idaho Power is the principal operating subsidiary of IDACORP, Inc. (IDACORP), a holding company formed in 1998. Idaho Power is an electric utility engaged in the generation, transmission, distribution, sale, and purchase of electric energy and capacity with a service area covering approximately 24,000 square miles in southern Idaho and eastern Oregon. On February 13, 2026, Idaho Power signed an asset purchase agreement with OTEC for the sale of Idaho Power's electric distribution business and certain transmission assets in the state of Oregon. Refer to Note 19 - "Sale of Oregon Assets" for additional information regarding the Oregon Sale. Idaho Power is regulated primarily by the state utility regulatory commissions of Idaho and Oregon and the Federal Energy Regulatory Commission (FERC). Idaho Power is the parent of Idaho Energy Resources Co. (IERCo), a joint-owner of BCC, which mines and supplies coal to the Jim Bridger plant owned in part by Idaho Power.

Basis of Reporting

Idaho Power's financial statements include the assets, liabilities, revenues, and expenses of the company have been prepared in accordance with the accounting requirements of the FERC as set forth in the 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 (U.S. GAAP). As required by the FERC, Idaho Power accounts for its investments in its majority-owned subsidiary on the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiary as required by U.S. GAAP. The accompanying financial statements include Idaho Power's proportionate share of the utility plant and related operations resulting from its interest in jointly-owned plants. In addition, under the requirements of the FERC, there are differences from U.S. GAAP in the presentation of (1) current portion of long-term debt, (2) assets and liabilities for cost of removal of assets, (3) regulatory assets and liabilities (4) deferred income taxes, (5) income tax expense, (6) non-utility revenues, (7) accrued taxes, and (8) debt issue costs.

Management Estimates

Management makes estimates and assumptions when preparing financial statements in conformity with GAAP. These estimates and assumptions include, among others, those related to rate regulation, retirement benefits, contingencies, asset impairment, income taxes, unbilled receivables, and the allowance for uncollectible accounts. These estimates and assumptions affect the reported amounts of assets and liabilities and the 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. These estimates involve judgments with respect to, among other things, future economic factors that are difficult to predict and are beyond management's control. Accordingly, actual results could differ from those estimates.

Regulation of Utility Operations

As a regulated utility, many of Idaho Power's fundamental business decisions are subject to the approval of governmental agencies, including the prices that Idaho Power is authorized to charge for its electric service. These approvals are a critical factor in determining Idaho Power's results of operations and financial condition.

Idaho Power meets the requirements under GAAP to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Idaho Power's financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment; regulatory assets and liabilities; operating revenues; other operations and maintenance (O&M) expense; depreciation and amortization expense; and income tax expense. The application of accounting principles related to regulated operations sometimes results in Idaho Power recording expenses and revenues in a different period than when an unregulated entity would record such expenses and revenues. In these instances, the amounts are deferred or accrued as regulatory assets or regulatory liabilities on the balance sheet. Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered from customers through future rates. Regulatory liabilities represent obligations to make refunds to customers for previous collections, or represent amounts collected in advance of incurring an expense. The effects of applying these regulatory accounting principles to Idaho Power's operations are discussed in more detail in Note 3 - "Regulatory Matters."

System of Accounts

The accounting records of Idaho Power conform to the Uniform System of Accounts prescribed by the FERC and adopted by the public utility commissions of Idaho, Oregon, and Wyoming.

Cash and Cash Equivalents

Cash and cash equivalents include cash on-hand and highly liquid temporary investments that mature within 90 days of the date of acquisition.

Receivables and Allowance for Uncollectible Accounts

Customer receivables are recorded at the invoiced amounts and do not bear interest. A late payment fee of one percent and 2.4 percent in Idaho Power's Idaho and Oregon jurisdictions, respectively, may be assessed per month on account balances after 30 days. An allowance is recorded for potential uncollectible accounts. The measurement of expected credit losses on Idaho Power accounts receivable is based on historical experience, current economic conditions, and forecasted information that may affect collections on the outstanding balance. Generally, this includes adjustments based upon a combination of historical write-off experience, aging of accounts receivable, an analysis of specific customer accounts, and an evaluation of whether there are current or forecasted economic conditions that might cause variation in collection from the historical experience. Adjustments are charged to income. Customer accounts receivable balances that remain outstanding after reasonable collection efforts are written off.

The following table provides a rollforward of the allowance for uncollectible accounts related to customer receivables (in thousands of dollars):

	Year Ended	
	December 31,	
	2025	2024
	\$	\$
Balance at beginning of period	5,071	4,869
Additions to the allowance	3,004	4,523
Write-offs, net of recoveries	(4,287)	(4,321)
	\$	\$
Balance at end of period	3,788	5,071
Allowance for uncollectible accounts as a percentage of customer receivables	3.7 %	4.2 %

Other receivables are also reviewed for impairment periodically, based upon transaction-specific facts. When it is probable that Idaho Power will be unable to collect all amounts due according to the contractual terms of the agreement, an allowance is established for the estimated uncollectible portion of the receivable and charged to income.

There were no impaired receivables without related allowances at December 31, 2025 and 2024. Once a receivable is determined to be impaired, any further interest income recognized is fully reserved.

Derivative Financial Instruments

Financial instruments such as commodity futures, forwards, options, and swaps are used to manage exposure to commodity price risk in the electricity and natural gas markets. All derivative instruments are recognized as either assets or liabilities at fair value on the balance sheet unless they are designated as normal purchases and normal sales. With the exception of forward contracts for the purchase of natural gas for use at Idaho Power's natural gas generation facilities and a nominal number of power transactions, Idaho Power's physical forward contracts are designated as normal purchases and normal sales. Because of Idaho Power's regulatory accounting mechanisms, Idaho Power records the unrealized changes in fair value of derivative instruments related to power supply as regulatory assets or liabilities.

Revenues

Operating revenues are generally recorded when service is rendered or energy is delivered to customers. Idaho Power accrues estimated unbilled receivables for electric services delivered to customers but not yet billed at year-end. Idaho Power does not report any collections of franchise fees and similar taxes related to energy consumption on the income statement. In addition, regulatory mechanisms in place in Idaho and Oregon affect the reported amount of revenue. The effects of applying these regulatory mechanisms are discussed in more detail in Note 4 - "Revenues."

Property, Plant, and Equipment and Depreciation

The cost of utility plant in service represents the original cost of contracted services, direct labor and material, Allowance for Funds Used During Construction (AFUDC), and indirect charges for engineering, supervision, and similar overhead items. Repair and maintenance costs associated with planned major maintenance are expensed as the costs are incurred, as are maintenance and repairs of property and replacements and renewals of items determined to be less than units of property. For utility property replaced or renewed, the original cost plus removal cost less salvage is charged to accumulated provision for depreciation, while the cost of related replacements and renewals is added to property, plant, and equipment.

All utility plant in service is depreciated using the straight-line method at rates approved by regulatory authorities. Annual depreciation provisions as a percent of average depreciable utility plant in service approximated 3.2 percent in 2025 and 3.1 percent in 2024.

During the period of construction, costs expected to be included in the final value of the constructed asset, and depreciated once the asset is complete and placed in service, are classified as construction work in progress on the balance sheets. If the project becomes probable of being abandoned, these costs are expensed in the period such determination is made. Idaho Power may seek recovery of these costs in customer rates, although there can be no guarantee such recovery would be granted.

Long-lived assets are periodically reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the undiscounted expected future cash flows from an asset is less than the carrying value of the asset, impairment is recognized in the financial statements. There were no material impairments of long-lived assets in 2025 and 2024.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, for the HCC relicensing project, cash is not realized currently from such allowance; it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. Idaho Power's weighted-average monthly AFUDC rate was 7.2 percent for both 2025 and 2024.

Income Taxes

Idaho Power account for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax

consequences of events that have been included in the financial statements. Under this method (commonly referred to as normalized accounting), deferred tax assets and liabilities are determined based on the differences between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. In general, deferred income tax expense or benefit for a reporting period is recognized as the change in deferred tax assets and liabilities from the beginning to the end of the period. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date unless Idaho Power's primary regulator, the Idaho Public Utilities Commission (IPUC), orders direct deferral of the effect of the change in tax rates over a longer period of time.

Consistent with orders and directives of the IPUC, unless contrary to applicable income tax guidance, Idaho Power does not record deferred income tax expense or benefit for certain income tax temporary differences and instead recognizes the tax impact currently (commonly referred to as flow-through accounting) for rate making and financial reporting. Therefore, Idaho Power's effective income tax rate is impacted as these differences arise and reverse. Idaho Power recognizes such adjustments as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates.

Idaho Power uses judgment, estimation, and historical data in developing the provision for income taxes and the reporting of tax-related assets and liabilities, including development of current year tax depreciation, capitalized repair costs, capitalized overheads, and other items. Income taxes can be impacted by changes in tax laws and regulations, interpretations by taxing authorities, changes to accounting guidance, and actions by federal or state public utility regulators. Actual income taxes could vary from estimated amounts and may result in favorable or unfavorable impacts to net income, cash flows, and tax-related assets and liabilities.

In compliance with the federal income tax requirements for the use of accelerated tax depreciation, Idaho Power records deferred income taxes related to its plant assets for the difference between income tax depreciation and book depreciation used for financial statement purposes. Deferred income taxes are recorded for other temporary differences unless accounted for using flow-through.

Investment tax credits earned on regulated assets are deferred and amortized to income over the estimated service lives of the related properties.

Income taxes are discussed in more detail in Note 2 - "Income Taxes."

Other Accounting Policies

Debt discount, expense, and premium are deferred and amortized over the terms of the respective debt issuances. Losses on reacquired debt and associated costs are amortized over the life of the associated replacement debt, as allowed under regulatory accounting.

New and Recently Adopted Accounting Pronouncements

Recently Adopted Accounting Pronouncements

In December 2023, the FASB issued ASU 2023-09, *Income Taxes (Topic 740): Improvements to Income Tax Disclosures* which expands the disclosure requirements for income taxes, specifically related to the rate reconciliation and income taxes paid. This ASU is effective for annual periods beginning after December 15, 2024, with early adoption permitted. The amendments in this ASU are required to be applied prospectively and are allowed to be applied retrospectively. Idaho Power adopted this ASU on January 1, 2025, for annual periods. The amendments in this ASU have been applied retrospectively. See Note 2 - "Income Taxes" for expanded disclosure required by this ASU.

There have been no other recently adopted accounting pronouncements that have had a material impact on Idaho Power's financial statements.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2025, up to February 19, 2026, the date that Idaho Power Company's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through [April 13, 2026]. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

2. INCOME TAXES

Reconciliations between the statutory federal income tax rate and the effective tax rate for the years ended December 31 are presented below (in thousands of dollars, except percentages):

	2025		2024	
Income before income taxes	\$ 302,601		\$ 297,936	
US federal income tax expense at statutory rate	63,546	21.0 %	62,567	21.0 %
State income taxes, net of federal				

Income tax effect ⁽¹⁾	12,192	4.0 %	14,122	4.7 %
Flow-through accounting and other effects of rate regulation:				
Equity earnings of subsidiary companies	(472)	(0.2)%	(347)	(0.1)%
AFUDC	(20,727)	(6.8) %	(17,015)	(5.7) %
Capitalized interest	7,721	2.6 %	5,493	1.8 %
Removal costs	(5,707)	(1.9) %	(5,109)	(1.7) %
Capitalized overhead costs	(2,100)	(0.7) %	(2,100)	(0.7) %
Capitalized repair costs	(24,150)	(8.0) %	(19,320)	(6.5) %
Depreciation	22,001	7.3 %	18,705	6.3 %
Excess deferred income tax reversal	(9,723)	(3.2) %	(10,047)	(3.4) %
Income tax return adjustments	(8,175)	(2.7) %	1,865	0.6 %
State related	687	0.2 %	6,378	2.1 %
Other, net	(577)	(0.2) %	759	0.3 %
Tax credits:				
Investment tax credits - federal	(7,208)	(2.4) %	(4,480)	(1.5) %
Investment tax credits - Idaho	—	— %	(3,791)	(1.3) %
Accumulated deferred investment tax credits - federal	(7,017)	(2.3) %	(8,712)	(2.9) %
Accumulated deferred investment tax credits - Idaho	(33,319)	(11.0) %	(21,119)	(7.1) %
Nontaxable or nondeductible items	(233)	(0.1) %	(517)	(0.2) %
Total income tax (benefit) expense and effective tax rate	\$(13,261)	(4.4) %	\$17,332	5.8 %

(1) State taxes in Idaho made up the majority (greater than 50%) of the tax effect in this category.

The items comprising income tax expense for the years ended December 31 are presented below (in thousands of dollars):

	2025	2024
Income taxes current:		
Federal	\$ 22,026	\$ 14,300
State	8,128	12,674
Total	30,154	26,974
Income taxes deferred:		
Federal	(29,991)	(61,751)
State	(18,826)	(12,735)
Total	(48,817)	(74,486)
Investment tax credits:		
Deferred	52,946	102,946
Restored	(47,544)	(38,102)
Total	5,402	64,844
Real estate-related investments at IFS	—	—
Total income tax (benefit) expense	\$ (13,261)	\$ 17,332

The components of the net deferred tax liability as of December 31 are presented below (in thousands of dollars):

	2025	2024
Deferred tax assets:		
Regulatory liabilities	\$ 121,489	\$ 127,634
Deferred compensation	24,483	24,782
Deferred revenue	70,326	64,592
Tax credits	67,930	53,859
Retirement benefits	19,533	26,495
Other	23,565	13,515
Total	327,326	310,877
Deferred tax liabilities:		
Property, plant and equipment		

	235,849	243,454
Regulatory assets		
	821,346	811,054
Retirement benefits		
	65,214	75,716
Wildfire mitigation plan deferral		
	22,252	16,272
Other		
	7,762	12,278
Total	1,152,423	1,158,774
Net deferred tax liabilities	\$ 825,097	\$ 847,897

IDACORP's tax allocation agreement provides that each member of its consolidated group compute its income taxes on a separate company basis. Amounts payable or refundable are settled through IDACORP and are reported as taxes accrued or income taxes receivable, respectively, on the balance sheets of Idaho Power. See Note 1 - "Summary of Significant Accounting Policies" for further discussion of accounting policies related to income taxes.

Supplemental Disclosure of Cash Flow Information

Supplemental cash flow information related to cash paid for income taxes for the years ended December 31 are presented below (in thousands of dollars):

	2025	2024
Federal	\$ 12,326	\$ 24,469
Idaho	7,522	5,598
Other	841	905
Total cash paid to IDACORP related to income taxes	\$ 20,689	\$ 30,972

Uncertain Tax Positions

Idaho Power believes that it has no material income tax uncertainties for 2025 and prior tax years. Idaho Power recognizes interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense.

Idaho Power is subject to examination by its major tax jurisdictions - United States federal and the State of Idaho. The open tax years for examination are 2023 through 2025 for federal and 2022 through 2025 for Idaho. In May 2009, IDACORP formally entered the U.S. Internal Revenue Service Compliance Assurance Process (CAP) program for its 2009 tax year and has remained in the CAP program for all subsequent years.

Excess Deferred Income Taxes

Following the enactment of income tax reform in 2017, Idaho Power was required to remeasure its deferred tax assets and liabilities at the new federal corporate income tax rate which resulted in lower net deferred tax liabilities and the establishment of a net regulatory liability for its depreciation-related excess deferred income taxes (EDIT). Idaho Power's deferred taxes for depreciation-related temporary differences on its public utility property are subject to the normalization method of accounting. As provided in the 2017 income tax reform statute, the normalization method requires the use of either the average rate assumption method (ARAM) or the alternative method for the reversal of the EDIT. In 2021, Idaho Power began using the alternative method for the EDIT reversal pursuant to the interpretation of an Internal Revenue Service revenue procedure and series of related private letter rulings. The alternative method results in the ratable return of the EDIT to customers over the remaining regulatory lives of Idaho Power's plant assets. For fiscal years 2018-2020, the ARAM method was used to reverse the EDIT.

3. REGULATORY MATTERS

Idaho Power's financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. Included below is a summary of Idaho Power's regulatory assets and liabilities, as well as a discussion of notable regulatory matters affecting customer rates.

Regulatory Assets and Liabilities

The application of accounting principles related to regulated operations sometimes results in Idaho Power recording some expenses and revenues in a different period than when an unregulated enterprise would record those expenses and revenues. Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered from customers through future rates. Regulatory liabilities represent obligations to make refunds to customers for previous collections, or represent amounts collected in advance of incurring an expense.

The following table presents a summary of Idaho Power's regulatory assets and liabilities (in thousands of dollars):

Description	As of December 31, 2025				Total as of December 31,	
	Remaining Amortization Period	Earning a Return ⁽¹⁾	Not Earning a Return	31,		
				2025	2024	
Regulatory Assets:						
Income taxes ⁽²⁾		\$ —	\$ 821,346	\$ 821,346	\$ 811,054	
Pension expense deferrals ⁽³⁾		245,508	1,832	247,340	252,197	
Mark-to-market assets ⁽⁴⁾		—	49,520	49,520	28,118	
Unfunded postretirement benefits ⁽⁵⁾		—	—	—	18,824	
Power supply costs ⁽⁶⁾		—	—	—	10,672	
Fixed cost adjustment (FCA) ⁽⁶⁾	2026-2027	8,205	(1,350)	6,855	17,761	
North Valmy plant settlements ⁽⁶⁾	2026-2033	83,941	—	83,941	80,767	
Jim Bridger plant settlement ⁽⁶⁾	2026-2030	151,739	12,921	164,660	147,451	
Wildfire Mitigation Plan deferral ⁽⁶⁾		—	91,670	91,670	63,966	
Asset retirement obligations ⁽⁷⁾		—	62,166	62,166	37,842	
Long-term service agreement	2026-2043	11,313	7,326	18,639	19,796	
Other	2026-2056	4,596	13,726	18,322	11,089	
Total		\$ 505,302	\$ 1,059,157	\$ 1,564,459	\$ 1,499,537	

Regulatory Liabilities:

Income taxes ⁽⁸⁾		\$ —	\$ 121,489	\$ 121,489	\$ 127,634	
Depreciation-related excess deferred income taxes ⁽⁹⁾		128,180	—	128,180	137,903	
Energy efficiency program costs		16,493	—	16,493	9,277	
Power supply costs ⁽⁶⁾	2026-2027	53,502	—	53,502	3,949	
Unfunded postretirement benefits ⁽⁵⁾		—	11,785	11,785	—	
Tax reform accrual for future amortization ⁽¹⁰⁾		—	44,423	44,423	42,266	
Other		4,168	3,839	8,007	15,852	
Total		\$ 202,343	\$ 181,536	\$ 383,879	\$ 336,881	

(1) Earning a return includes either interest or a return on the investment as a component of rate base at the allowed rate of return. The interest rate on deferral accounts is published annually by the IPUC and Public Utility Commission of Oregon (OPUC). The applicable rates for 2025 were 5.0% and 4.5%, respectively.

(2) Represents flow-through income tax accounting differences which have a corresponding deferred tax liability disclosed in Note 2 - "Income Taxes."

(3) Idaho Power records a regulatory asset for the difference between net periodic pension cost and pension cost considered for rate-making purposes relating to Idaho Power's defined benefit pension plan. In its Idaho jurisdiction, Idaho Power's inclusion of pension costs for the establishment of retail rates is based upon contributions made to the pension plan. This regulatory asset account represents the difference between cumulative cash contributions and amounts collected in rates. Deferred costs are amortized into expense as the amounts are provided for in Idaho retail revenues.

(4) This item is discussed in more detail in Note 15 - "Derivative Financial Instruments."

(5) Represents the unfunded obligation of Idaho Power's pension and postretirement benefit plans, which are discussed in Note 11 - "Benefit Plans."

(6) This item is discussed in more detail in this Note 3 - "Regulatory Matters."

(7) Asset retirement obligations and removal costs are discussed in Note 13 - "Asset Retirement Obligations (ARO)."

(8) Represents the tax gross-up related to the depreciation-related excess deferred income taxes and investment tax credits included in this table and has a corresponding deferred tax asset disclosed in Note 2 - "Income Taxes."

(9) For depreciation-related temporary differences under the normalized tax accounting method, the resulting excess deferred taxes will flow back to customers ratably over the remaining regulatory lives of Idaho Power's plant assets under the alternative method provided in the statute.

(10) Represents amount accrued under the May 2018 Idaho tax reform settlement stipulation (described below) for the future amortization of existing or future unspecified regulatory deferrals that would otherwise be a future liability recoverable from Idaho customers.

Idaho Power's regulatory assets and liabilities are typically amortized over the period in which they are reflected in customer rates. In the event that recovery of Idaho Power's costs through rates becomes unlikely or uncertain, regulatory accounting would no longer apply to some or all of Idaho Power's operations and the items above may represent stranded investments. If not allowed full recovery of these items, Idaho Power would be required to write off the applicable portion, which could have a materially adverse financial impact.

Power Cost Adjustment Mechanisms and Deferred Power Supply Costs

In both its Idaho and Oregon jurisdictions, Idaho Power's power cost adjustment mechanisms address the volatility of power supply costs and provide for annual adjustments to the rates charged to its retail customers. The power cost adjustment mechanisms compare Idaho Power's actual net power supply costs (primarily fuel and purchased power less wholesale energy sales) against net power supply costs being recovered in Idaho Power's retail rates. Under the power cost adjustment mechanisms, certain differences between actual net power supply costs incurred by Idaho Power and costs being recovered in retail rates are recorded as a deferred charge or accrued as a credit on the balance sheets for future recovery or refund. The power supply costs deferred or accrued primarily result from changes in the levels of Idaho Power's own hydroelectric generation, changes in contracted power purchase prices and volumes, changes in wholesale market prices and transaction volumes, and changes in fuel prices.

Idaho Jurisdiction Power Cost Adjustment Mechanism (PCA): In the Idaho jurisdiction, the annual PCA consists of (a) a forecast component, based on a forecast of net power supply costs in the coming year as compared with net power supply costs included in base rates; and (b) a balancing component that trues up the difference between the previous year's actual net power supply costs and the costs collected in the previous year's forecast component. The latter component ensures that, over time, the actual collection or refund of net power supply costs matches the amounts authorized. The Idaho-jurisdiction PCA year runs from April 1 through March 31. Amounts deferred or accrued during the PCA year are primarily recovered or refunded during the subsequent June 1 through May 31 period. The PCA mechanism includes:

- a cost or benefit sharing ratio that allocates the deviations in net power supply expenses between customers (95 percent) and Idaho Power (5 percent), with the exceptions of expenses associated with PURPA power purchases, export credit mechanisms, a battery storage lease, and demand response incentive payments, which are allocated 100 percent to customers; and
- a sales-based adjustment intended to ensure that power supply expense recovery resulting solely from sales volume changes does not distort the results of the mechanism.

Beginning April 1, 2024, the difference between actual and base-level third-party transmission wheeling revenues are tracked and incorporated into the balancing component of the PCA, as authorized by the IPUC in March 2025. In May 2025, the IPUC issued an order approving a \$94.8 million net decrease in PCA revenues as compared with the prior collection period, effective for the PCA collection period from June 1, 2025, to May 31, 2026. The net decrease in PCA revenues reflected a decrease in the balancing adjustment, which was due primarily to the completed recovery of the 2023 deferred PCA costs, which were recovered over a two-year period as ordered by the IPUC. The 2025 Settlement Stipulation, described in more detail below, modified PCA collection effective January 1, 2026, to account for the new system base level NPSE of \$468.8 million.

The table below summarizes the three most recent Idaho-jurisdiction PCA rate adjustments from Idaho Power's annual PCA filings, which also include non-PCA-related rate adjustments as ordered by the IPUC:

Effective Date	\$ Change (millions)	Notes
June 1, 2025	\$ (94.8)	The \$94.8 million net decrease in PCA rates reflects a decrease in the balancing adjustment, which is due primarily to the completed recovery of the 2023 balancing adjustment, which was recovered over two years.
June 1, 2024	\$ (35.7)	The \$35.7 million net decrease in PCA rates reflected forecasted improved hydropower generation during the April 2024 to March 2025 PCA deferral period.

Oregon Jurisdiction Power Cost Adjustment Mechanism: Idaho Power's power cost recovery mechanism in Oregon has two components: an annual power cost update (APCU) and a power cost adjustment mechanism (PCAM). The APCU allows Idaho Power to reestablish its Oregon base net power supply costs annually, separate from a general rate case, and to forecast net power supply costs for the upcoming water year. The PCAM is a true-up filed annually in February. The PCAM filing calculates the deviation between actual net power supply expenses incurred for the preceding calendar year and the net power supply expenses recovered through the APCU for the same period. In May 2025, the OPUC approved a settlement stipulation between Idaho Power and intervening parties for its APCU in Oregon. The settlement resulted in an overall rate decrease of \$1.8 million in Oregon-jurisdictional rates effective June 1, 2025. Idaho Power's 2024 June 1 APCU rate change was a decrease of \$6.9 million.

Notable Idaho Base Rate Adjustments

Idaho base rates were most recently established through a general rate case in 2025, which was resolved by the 2025 Settlement Stipulation, with rate changes effective January 1, 2026. Previously, base rates were established in the 2024 Idaho Limited-Issue Rate Case and in a general rate case in 2023, which was resolved by the 2023 Settlement Stipulation.

2025 Idaho General Rate Case: In May 2025, Idaho Power filed a general rate case with the IPUC. The general rate case was resolved in December 2025, when the IPUC issued an order (the Order) approving the 2025 Settlement Stipulation, entered into by Idaho Power, the Staff of the IPUC, and several of the intervening parties.

The 2025 Settlement Stipulation contains the following significant terms, among other items:

- Idaho Power will implement revised tariff schedules designed to increase annual Idaho-jurisdictional retail revenue by approximately \$110.0 million, or 7.48 percent, effective January 1, 2026. The approximate \$110.0 million of additional annual revenue is inclusive of a PCA rate increase of \$13.1 million;
- a 9.6 percent return on equity and a 7.41 percent authorized rate of return based on the filed cost of debt and capital structure, applied to an Idaho-jurisdictional rate base of approximately \$4.9 billion (which is largely based on the average of monthly average plant balances for January through December 2025);
- a base level NPSE of approximately \$468.8 million, a decrease of \$16.1 million from the currently approved base level NPSE;
- updates to the FCA mechanism rates to reflect approved fixed costs and Idaho Power's proposed rate designs;
- continued deferral of certain wildfire mitigation related costs, including incremental vegetation management and insurance costs, as measured primarily from 2024 actual costs, through the earlier of Idaho Power's next general rate case or 2027;
- modifications to Idaho Power's Accumulated Deferred Investment Tax Credits (ADITC) and revenue sharing mechanism: (1) to include an additional amount of investment tax credits equal to the total of existing ADITCs not currently eligible for accelerated amortization under the mechanism and all investment tax credits generated through the end of calendar-year 2028; (2) to establish an annual cap of \$55 million on the amount of accelerated amortization of ADITCs for calendar year 2026 and thereafter; (3) to re-affirm the existing minimum specified Idaho-jurisdiction return on year-end equity (Idaho ROE) of 9.12 percent for additional amortization of ADITCs; (4) to re-affirm the existing 9.6 percent Idaho ROE as the threshold for revenue sharing of Idaho-jurisdiction earnings between Idaho Power and Idaho customers; and (5) to continue to implement all revenue sharing through the PCA; and
- agreement that Idaho Power's share of capital expenditures at jointly-owned coal-fired plants through year-end 2024 are included for recovery in the stipulated revenue requirement.

At the time of the 2025 Settlement Stipulation, Staff of the IPUC had completed its prudence review of capital projects included in the test year rate base through July 2025. The IPUC Staff will address the prudence of investments placed in service after July 2025 in Idaho Power's next Idaho general rate case. Neither the Order nor the 2025 Settlement Stipulation precludes Idaho Power from filing another general rate case in Idaho at any time in the future.

Under the modified ADITC and Revenue Sharing mechanism, if Idaho Power's annual Idaho ROE in any year exceeds 9.6 percent, the amount of earnings exceeding 9.6 percent will be allocated 80.0 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's PCA, and 20.0 percent to Idaho Power. In 2025, Idaho Power recorded amortization of \$40.3 million of ADITC. Accordingly, at December 31, 2025, \$167.8 million of ADITC remained available for future use under the terms of the

2025 Settlement Stipulation, the 2023 Settlement Stipulation, and the 2018 Settlement Stipulation described below.

2024 Idaho Limited-Issue Rate Case: Idaho Power filed the 2024 Idaho Limited-Issue Rate Case in May 2024, focused on revenue requirements for 2024 incremental plant additions and incremental ongoing labor costs. On December 31, 2024, the IPUC issued its order in the 2024 Idaho Limited-Issue Rate Case, providing that Idaho Power implement revised tariff schedules designed to increase annual Idaho-jurisdictional retail revenue by \$50.6 million, or 3.7 percent, effective January 1, 2025. The order was subsequently modified by an errata issued on January 21, 2025, which reduced the revenue increase called for under the order to \$50.1 million. The order did not adjust the overall rate of return approved in the 2023 Settlement Stipulation or make changes to Idaho regulatory mechanisms such as the PCA, FCA, and energy efficiency rider.

2023 Idaho General Rate Case: In June 2023, Idaho Power filed a general rate case with the IPUC. In December 2023, the IPUC issued an order approving the 2023 Settlement Stipulation settling the general rate case. The order and the 2023 Settlement Stipulation provided for the following significant terms, among other items:

- Implementation of revised tariff schedules designed to increase annual Idaho-jurisdictional retail revenue by \$54.7 million, or 4.25 percent, effective January 1, 2024. The \$54.7 million of additional annual revenue was net of an Idaho-jurisdiction PCA rate decrease of \$168.3 million and a reduction to annual energy efficiency rider collection of \$3.5 million, each of which was transferred into base rates;
- A 9.6 percent return on equity and a 7.247 percent authorized rate of return based on a non-specified cost of debt and capital structure, applied to an Idaho-jurisdictional rate base of approximately \$3.8 billion;
- Modifications to the PCA including establishment of a new level of base net power supply expense of \$484.9 million, which included the transfer of \$168.3 million from then-current PCA rates to base rates;
- An annual \$18 million increase in collection of Idaho Power's regulatory asset associated with its defined benefit pension plan contributions;
- Modifications to Idaho Power's ADITC and revenue sharing mechanism beginning in 2024 to, among other items, (1) establish a minimum specified Idaho ROE of 9.12 percent for additional amortization of ADITCs; and (2) establish a 9.6 percent Idaho ROE as the threshold for revenue sharing of Idaho-jurisdiction earnings between Idaho Power and Idaho customers; and
- Agreement that Idaho Power's capital expenditures through year-end 2022 were prudently incurred.

May 2018 Idaho Tax Reform Settlement Stipulation: In May 2018, the IPUC issued an order approving a settlement stipulation (2018 Settlement Stipulation) related to income tax reform. Beginning June 1, 2018, the 2018 Settlement Stipulation provided an annual (a) \$18.7 million reduction to Idaho customer base rates and (b) \$7.4 million amortization of existing regulatory deferrals for specified items or future amortization of other existing or future unspecified regulatory deferrals that would otherwise be a future regulatory asset recoverable from Idaho customers. The 2018 Settlement Stipulation also provided for the indefinite extension, with modifications, of a previous 2014 settlement stipulation beyond its termination date of December 31, 2019, with modified terms related to the ADITC and revenue sharing mechanism that became effective January 1, 2020. Idaho Power's base rates and ADITC and revenue sharing mechanism were modified by the 2025 Settlement Stipulation and the 2023 Settlement Stipulation, as described above.

North Valmy Base Rate Adjustment Settlement Stipulations: Idaho Power has settlement stipulations in place in Idaho and Oregon related to the end of its participation in coal-fired operations of both units of its jointly-owned North Valmy plant. Idaho Power ceased participation in coal-fired operations at unit 1 in 2019, and coal-fired operations at unit 2 ceased at the end of 2025. The IPUC-approved settlement stipulation provides for (1) accelerated depreciation for the North Valmy plant to allow the coal-related plant assets to be fully depreciated and recovered by December 31, 2028, (2) Idaho Power to use prudent and commercially reasonable efforts to end its participation in coal-fired operations at the North Valmy plant as described above, (3) a balancing account to track the incremental costs, benefits, and required regulatory accounting associated with ceasing participation in coal-fired operations at the North Valmy plant, and (4) increased customer rates related to the associated incremental annual levelized revenue requirement. If actual costs incurred differ from forecasted amounts included in the settlement stipulation, collection or refund of any differences would be subject to regulatory approval. The 2025 Settlement Stipulation made modifications to the Idaho North Valmy settlement stipulation, including updated coal-related investments through 2024 and investment forecasts through 2025. On December 31, 2025, the accelerated depreciation associated with coal-related investments at the North Valmy plant was completed and the amounts removed from Oregon customer rates.

Jim Bridger Power Plant Rate Base Adjustment and Recovery: In 2022, the IPUC authorized Idaho Power to (1) accelerate depreciation for the Jim Bridger plant to allow the coal-related plant assets to be fully depreciated and recovered by December 31, 2030, (2) establish a balancing account to track the incremental costs, benefits, and required regulatory accounting associated with its plan to cease participation in coal-fired operations at the Jim Bridger plant in 2028, and (3) increase customer rates related to the associated incremental annual levelized revenue requirement (Bridger Recovery Mechanism). The 2025 Settlement Stipulation made modifications to the Bridger Recovery Mechanism, including updated coal-related investments through 2024, updated investment forecasts through 2028, and the inclusion of total other O&M expenses associated with operations of the Jim Bridger plant. The Bridger Recovery Mechanism allows Idaho Power to earn a return on and recover through 2030 the net book value of coal-related assets at the Jim Bridger plant as of December 31, 2024, as well as forecasted coal-related investments.

Idaho Power anticipates making future filings with the IPUC that may result in periodic adjustments to rates to true up variances between revenue collections and actual revenue requirement amounts.

Recovery of Incremental AFUDC Associated with HCC: In March 2025, Idaho Power filed an application with the IPUC requesting an order authorizing an increase of \$29.7 million in the annual cash collection of incremental financing costs, or AFUDC, associated with relicensing of the HCC project. In September 2025, the IPUC approved Idaho Power's proposed increase in annual cash collection to recover AFUDC associated with relicensing of the HCC project, effective October 1, 2025.

Other Notable Idaho Regulatory Matters Affecting Customer Rates

Fixed Cost Adjustment: The FCA mechanism, applicable to Idaho residential and small commercial customers, is designed to remove a portion of Idaho Power's financial disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kWh charge and linking it instead to a set amount per customer. Under Idaho Power's current rate design, recovery of a portion of fixed costs is included in the variable kWh charge, which may result in over-collection or under-collection of fixed costs. To return over-collection to customers or to collect under-collection from customers, the FCA mechanism allows Idaho Power to accrue, or defer, the difference between the authorized fixed-cost recovery amount per customer and the actual fixed costs per customer recovered by Idaho Power during the year. The IPUC has discretion to cap the annual increase in the FCA recovery at 3 percent of base revenue, with any excess deferred for collection in a subsequent year. In May 2025, the IPUC issued an order approving a \$39.8 million decrease in recovery from the FCA from \$36.8 million to negative \$3.1 million for the 2024 FCA deferral, reflecting a refund to residential and small commercial customers of the 2024 FCA deferral balance of \$3.1 million, with new rates effective for the period from June 1, 2025 to May 31, 2026. Beginning with the 2026 FCA deferral, the 2025 Settlement Stipulation updated the authorized fixed-cost recovery amount per customer and per unit of energy within the FCA mechanism to support Idaho Power's proposed rate designs, as noted above.

The following table summarizes FCA amounts approved for (refund) or collection in the prior three FCA years:

FCA Year	Period Rates in Effect	Annual Amount
		(in millions of dollars)
2024	June 1, 2025 to May 31, 2026	\$(3.1)
2023	June 1, 2024 to May 31, 2025	\$36.8

Wildfire Mitigation Cost Recovery: In September 2025, the IPUC granted Idaho Power's request to defer for future recovery an estimated \$22.2 million of newly identified incremental O&M costs expected to be incurred in 2025 associated with expanded wildfire mitigation efforts. The IPUC also authorized the continued deferral of incremental insurance costs above the 2022 base established in the 2023 Settlement Stipulation. The 2025 Settlement Stipulation authorized Idaho Power to defer incremental O&M and insurance costs above the 2024 base through the earlier of the next general rate case or 2027. As of December 31, 2025, Idaho Power's deferral balance of Idaho-jurisdiction costs related to the WMP was \$88.2 million, of which \$73.9 million is approved to be amortized and collected in Idaho rates.

Hells Canyon Complex Relicensing Costs: In December 2025, Idaho Power filed an application with the IPUC requesting a determination that Idaho Power's expenditures from January 1, 2016 through year-end 2025 on relicensing of the HCC, including approximately \$305 million incurred from January 1, 2016 through September 30, 2025, were prudently incurred, and thus eligible for inclusion in retail rates in a future regulatory proceeding. As of the date of this report, the case remains pending.

Notable Oregon Regulatory Matters Affecting Customer Rates

Oregon Base Rate Changes: Oregon base rates were most recently established in a general rate case that Idaho Power filed with the OPUC in December 2023 and a separate case approved by the OPUC in December 2025 described below. In September 2024, the OPUC issued an order approving the 2024 Oregon Settlement Stipulations, which are settlement stipulations among Idaho Power and intervening parties settling the general rate case.

The OPUC order and the 2024 Oregon Settlement Stipulations contain the following significant terms, among other items:

- Implementation of revised tariff schedules designed to increase annual Oregon-jurisdiction revenue by \$6.7 million, or 12.14 percent; and
- A 9.5 percent Oregon-jurisdiction return on year-end equity and a 7.302 percent Oregon-jurisdiction authorized rate of return based on a 5.104 percent cost of debt and capital structure of 50 percent debt and 50 percent equity, applied to an Oregon-jurisdictional rate base of approximately \$188.9 million. The \$188.9 million of rate base excludes rate base associated with Idaho Power's jointly-owned North Valmy coal facilities, the costs of which are recovered under the separate rate mechanism noted above.

Rate changes from the 2024 Oregon Settlement Stipulations became effective on October 15, 2024. The 2024 Oregon Settlement Stipulations do not preclude Idaho Power from filing another general rate case or other limited issue proceeding in Oregon at any time in the future.

In December 2025, the OPUC issued an order approving a decrease in Oregon rates reflecting three offsetting adjustments: a decrease in rates of \$1.2 million due to the removal of coal-related costs at the North Valmy plant, a decrease in rates of \$0.1 million to return an outstanding regulatory liability related to the former Boardman plant, and an increase in rates of \$0.7 million to recover the amortization of deferred 2023 wildfire mitigation costs. The combined result was an overall rate decrease of \$0.6 million or 0.9 percent, effective January 1, 2026.

Wildfire Mitigation Cost Recovery: In December 2025, Idaho Power filed its 2026-2028 WMP with the OPUC along with an application requesting authorization to defer for future recovery an estimated \$3.1 million of newly identified incremental costs expected to be incurred in 2026 associated with expanded wildfire mitigation efforts. As of the date of this report, the case remains pending. As of December 31, 2025, Idaho Power's deferral balance of Oregon-jurisdiction costs related to the WMP was \$3.5 million, of which \$0.7 million is approved to be amortized and collected in Oregon rates.

Federal Regulatory Matters - Open Access Transmission Tariff Rates

Idaho Power uses a formula rate for transmission service provided under its OATT, which allows transmission rates to be updated annually based primarily on actual financial and operational data Idaho Power files with the FERC and allows Idaho Power to recover costs associated with its transmission system. Idaho Power's OATT rates submitted to the FERC in Idaho Power's four most recent annual OATT Final Informational Filings were as follows:

Period Rates in Effect	OATT Rate (per kW-year)
October 1, 2025 to September 30, 2026	\$ 34.16
October 1, 2024 to September 30, 2025	\$ 31.55
October 1, 2023 to September 30, 2024	\$ 30.74

Idaho Power's current OATT rate is based on a net annual transmission revenue requirement of \$148.5 million, which represents the OATT formulaic determination of Idaho Power's net cost of providing OATT-based transmission service.

Revenues from Contracts with Customers

Revenues from contracts with customers are primarily related to Idaho Power's regulated tariff-based sales of energy or related services. Generally, tariff-based sales do not involve a written contract, but are considered revenues from contracts with customers. Idaho Power assesses revenues on a contract-by-contract basis to determine the nature, amount, timing, and uncertainty, if any, of revenues being recognized.

Retail Revenues: Idaho Power's retail revenues primarily relate to the sale of electricity to customers based on regulated tariff-based prices. Idaho Power recognizes retail revenues in amounts for which it has the right to invoice the customer in the period when energy is delivered or services are provided to customers. The total energy price generally has a fixed component related to having service available and a usage-based component related to the demand, delivery, and consumption of energy. The revenues recognized reflect the consideration Idaho Power expects to be entitled to in exchange for energy and services. Retail customers are classified as residential, commercial, industrial, or irrigation. Approximately 95 percent of Idaho Power's retail revenue originates from customers located in Idaho, with the remainder originating from customers located in Oregon. Idaho Power's retail customer rates are based on Idaho Power's cost of service and are determined through general rate case proceedings, settlement stipulations, and other filings with the IPUC and OPUC. Changes in rates and changes in customer demand are typically the primary causes of fluctuations in retail revenue from period to period. The primary influences on changes in customer demand for electricity are weather, economic conditions (including growth in the number of Idaho Power customers), and energy efficiency. Idaho Power's utility revenues are not earned evenly during the year.

Retail revenues are billed monthly based on meter readings taken throughout the month. Payments for amounts billed are generally due from the customer within 15 days of billing. Idaho Power accrues estimated unbilled revenues for energy or related services delivered to customers but not yet billed at period-end based on actual meter readings at period-end and estimated rates.

Residential Customers: Idaho Power's energy sales to residential customers typically peak during the summer cooling season and winter heating season. Extreme temperatures increase sales to residential customers who use electricity for cooling and heating, compared with normal temperatures. Idaho Power's rate structure provides for higher rates during the summer when overall system loads are at their highest, and includes tiers such that rates increase as a customer's consumption level increases. These seasonal and tiered rate structures contribute to the seasonal fluctuations in revenues and earnings. Economic and demographic conditions can also affect residential customer demand; strong job growth and population growth in Idaho Power's service area have led to higher customer growth in recent years. Residential demand is also impacted by energy efficiency initiatives. Idaho Power's FCA mechanism mitigates some of the fluctuations caused by weather and energy efficiency initiatives.

Commercial Customers: Most businesses are included in Idaho Power's commercial customer class, as are small industrial companies, and public street and highway lighting accounts. Idaho Power's commercial customers are less influenced by weather conditions than residential customers, although weather does still affect commercial customer energy use. Economic conditions, including manufacturing activity levels, and energy efficiency initiatives also affect energy use of commercial customers.

Industrial Customers: Industrial customers consist of large industrial companies, including special contract customers. Energy use of industrial customers is primarily driven by economic conditions, with weather having little impact on this customer class.

Irrigation Customers: Irrigation customers use electricity to operate irrigation pumps, primarily during the agricultural growing season. The amount and timing of precipitation as well as temperature levels affect the timing and amounts of sales to irrigation customers, with increased precipitation during the agricultural growing season generally resulting in decreased sales.

Wholesale Energy Sales: As a public utility under the FPA, Idaho Power has been granted the authority to charge market-based rates for wholesale energy sales under its FERC tariff. Idaho Power's wholesale electricity sales are primarily to utilities and power marketers and are predominantly short-term and consist of a single performance obligation satisfied as energy is transferred to the counterparty. Idaho Power's wholesale energy sales depend largely on the availability of generation resources in excess of the amount necessary to serve customer loads as well as adequate market power prices and demand at the time when those resources are available. A reduction in any of those factors may lead to lower wholesale energy sales.

Transmission Wheeling-Related Revenues: As a public utility under the FPA, Idaho Power has been granted the authority to provide cost-based wholesale and retail access transmission services under its OATT. Services under the OATT are offered on a nondiscriminatory basis such that all potential customers have an equal opportunity to access the transmission system. Idaho Power's transmission revenue is primarily related to third parties reserving capacity on Idaho Power's transmission system to transmit electricity through Idaho Power's service area. Reservations are predominantly short-term contracts or on-demand when available, but may be part of a long-term capacity contract. Transmission wheeling-related revenues consist of a single performance obligation satisfied as capacity on Idaho Power's transmission system is provided to the third party. Transmission wheeling-related revenues are affected by changes in Idaho Power's OATT rate and customer demand. Demand for transmission services can be affected by regional market factors, such as loads and generation of utilities in Idaho Power's region.

Energy Efficiency Program Revenues: Idaho Power collects most of its energy efficiency program costs through an energy efficiency rider on customer bills. The rider collections are deferred until expenditures are incurred. Energy efficiency program expenditures funded through the rider are reported as an operating expense with an equal amount recognized in revenues, resulting in no net impact on earnings. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability. A liability balance indicates that Idaho Power has collected more than it has spent, and an asset balance indicates that Idaho Power has spent more than it has collected. At December 31, 2025, Idaho Power's energy efficiency rider balances were a \$13.4 million regulatory liability in the Idaho jurisdiction and a \$3.1 million regulatory liability in the Oregon jurisdiction.

Alternative Revenue Programs and Other Revenues

While revenues from contracts with customers make up most of Idaho Power's revenues, the IPUC has authorized the use of an additional regulatory mechanism, the FCA mechanism, which may increase or decrease tariff-based retail customer rates. The FCA mechanism is described in Note 3 - "Regulatory Matters." The FCA mechanism revenues include only the initial recognition of FCA revenues when they meet the regulator-specified conditions for recognition. Revenue from contracts with customers excludes the portion of the tariff price representing FCA revenues that Idaho Power initially recorded in prior periods when revenues met regulator-specified conditions. When Idaho Power includes those amounts in the price of utility service and billed to customers, Idaho Power records such amounts as recovery of the associated regulatory asset or liability and not as revenues.

The following table summarizes Idaho Power's long-term debt at December 31 (in thousands of dollars):

	2025	2024
First mortgage bonds:		
1.90% Series due 2030	\$ 80,000	\$ 80,000
6.00% Series due 2032	100,000	100,000
4.99% Series due 2032	23,000	23,000
5.50% Series due 2033	70,000	70,000
5.50% Series due 2034	50,000	50,000
5.875% Series due 2034	55,000	55,000
5.20% Series due 2034	300,000	300,000
5.30% Series due 2035	60,000	60,000
6.30% Series due 2037	140,000	140,000
6.25% Series due 2037	100,000	100,000
4.85% Series due 2040	100,000	100,000
4.30% Series due 2042	75,000	75,000
5.06% Series due 2042	25,000	25,000
5.06% Series due 2043	60,000	60,000
4.00% Series due 2043	75,000	75,000
3.65% Series due 2045	250,000	250,000
4.05% Series due 2046	120,000	120,000
4.20% Series due 2048	450,000	450,000
5.20% Series due 2053	62,000	62,000
5.50% Series due 2053	400,000	400,000
5.80% Series due 2054	350,000	350,000
5.70% Series due 2055	400,000	—
Total first mortgage bonds	3,345,000	2,945,000
Pollution control revenue bonds:		
1.70% Series due 2026 ⁽¹⁾	116,300	116,300
Total pollution control revenue bonds	116,300	116,300
American Falls Variable Rate bond guarantee due 2025	—	19,885
Unamortized premium/discount	12,507	16,150
Total Idaho Power outstanding debt⁽²⁾	3,473,807	3,097,335

(1) Sweetwater County Pollution Control Revenue Bonds are secured by the first mortgage bonds, bringing the total first mortgage bonds outstanding at December 31, 2025, to \$3.461 billion.

(2) At December 31, 2025 and 2024, the overall effective cost rate of Idaho Power's outstanding debt was 5.13 percent and 5.03 percent, respectively.

At December 31, 2025, the maturities for the aggregate amount of Idaho Power long-term debt outstanding were as follows (in thousands of dollars):

2026	2027	2028	2029	2030	Thereafter
\$ 116,300	\$ —	\$ —	\$ —	\$ 80,000	\$ 3,265,000

Long-Term Debt Issuances, Maturities, and Redemptions

On February 27, 2026, Idaho Power issued \$350 million in aggregate principal amount of 4.85% first mortgage bonds, secured medium-term notes, Series O, maturing on March 1, 2036.

On March 13, 2025, Idaho Power issued \$400 million in aggregate principal amount of 5.70% first mortgage bonds, secured medium-term notes, Series O, maturing on March 15, 2055.

On February 3, 2025, Idaho Power repaid \$19.9 million in aggregate principal amount of maturing variable rate American Falls Bonds.

On December 2, 2024, Idaho Power repaid \$49.8 million in aggregate principal amount of maturing 1.45% Humboldt County Pollution Control Revenue Bonds.

On August 12, 2024, Idaho Power issued \$300 million in aggregate principal amount of 5.20% first mortgage bonds, secured medium-term notes, Series M, maturing on August 15, 2034.

Idaho Power First Mortgage Bonds

Idaho Power's issuance of long-term indebtedness is subject to the approval of the IPUC, OPUC, and WPSC. In February and March 2024, Idaho Power received orders from the IPUC, OPUC, and WPSC authorizing the company to issue and sell from time to time up to \$1.2 billion in aggregate principal amount of debt securities and first mortgage bonds, subject to conditions specified in the orders. Authority from the IPUC is effective through December 31, 2026, subject to extensions upon request to the IPUC. The OPUC's and WPSC's orders do not impose a time limitation for issuances, but the OPUC order does impose a number of other conditions, including a requirement that the interest rates for the debt securities or first mortgage bonds fall within either (a) designated spreads over comparable U.S. Treasury rates or (b) a maximum interest rate limit of 8 percent. At December 31, 2025, \$500 million remained available for debt issuance under the regulatory orders.

In February 2025, Idaho Power filed a shelf registration statement with the SEC, which became effective upon filing, for the offer and sale of an unspecified principal amount of its first mortgage bonds. The issuance of first mortgage bonds requires that Idaho Power meet interest coverage and security provisions set forth in Idaho Power's Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented from time to time (Indenture). Future issuances of first mortgage bonds are subject to satisfaction of covenants and security provisions set forth in the Indenture, market conditions, regulatory authorizations, and covenants contained in other financing agreements.

In February 2025, Idaho Power entered into a selling agency agreement with seven banks named in the agreement in connection with the potential issuance and sale from time to time of up to \$2.1 billion aggregate principal amount of first mortgage bonds, secured medium-term notes, Series O (Series O Notes), under the Indenture. Also in February 2025, Idaho Power entered into the Fifty-third Supplemental Indenture, dated effective as of February 26, 2025, to the Indenture (Fifty-third Supplemental Indenture). The Fifty-third Supplemental Indenture provides for, among other items, the issuance of up to \$2.1 billion in aggregate principal amount of Series O Notes pursuant to the Indenture and increased the limit of the amount of first mortgage bonds at any one time outstanding to \$5.5 billion as provided in the Indenture. The amount issuable is also restricted by property, earnings, and other provisions of the Indenture and supplemental indentures to the Indenture. The Indenture requires that Idaho Power's net earnings be at least twice the annual interest requirements on all outstanding debt of equal or prior rank, including the bonds that Idaho Power may propose to issue. Under certain circumstances, the net earnings test does not apply, including the issuance of refunding bonds to retire outstanding bonds that mature in less than two years or that are of an equal or higher interest rate, or prior lien bonds.

The mortgage of the Indenture secures all bonds issued under the Indenture equally and ratably, without preference, priority, or distinction. First mortgage bonds issued in the future will also be secured by the mortgage of the Indenture. The lien constitutes a first mortgage on all the properties of Idaho Power, subject only to certain limited exceptions including liens for taxes and assessments that are not delinquent and minor excepted encumbrances. Certain of the properties of Idaho Power are subject to easements, leases, contracts, covenants, workmen's compensation awards, and similar encumbrances and minor defects common to properties. The mortgage of the Indenture does not create a lien on revenues or profits, or notes or accounts receivable, contracts or choses in action, except as permitted by law during a completed default, securities, or cash, except when pledged, or merchandise or equipment manufactured or acquired for resale. The mortgage of the Indenture creates a lien on the interest of Idaho Power in property subsequently acquired, other than excepted property, subject to limitations in the case of consolidation, merger, or sale of all or substantially all of the assets of Idaho Power. The Indenture requires Idaho Power to spend or appropriate 15 percent of its annual gross operating revenues for maintenance, retirement, or amortization of its properties. Idaho Power may, however, anticipate or make up these expenditures or appropriations within the 5 years that immediately follow or precede a particular year.

The Indenture limits the amount of additional first mortgage bonds that Idaho Power may issue to the sum of (a) the principal amount of retired first mortgage bonds and (b) 60 percent of total unfunded property additions, as defined in the Indenture. As of December 31, 2025, the maximum amount of additional first mortgage bonds Idaho Power could issue under this test was approximately \$2.3 billion. The Indenture also imposes a fixed cap of \$5.5 billion on the aggregate amount of first mortgage bonds that may be outstanding under the Indenture, which cap may be amended under certain conditions. As of December 31, 2025, Idaho Power could issue approximately \$2.0 billion of additional first mortgage bonds based on that aggregate cap.

6. COMMON STOCK

Idaho Power Common Stock

During 2025 and 2024, IDACORP contributed \$195 million and \$200 million, respectively, of additional capital to Idaho Power. During 2025 and 2024, no additional shares of Idaho Power common stock were issued.

Restrictions on Dividends

Idaho Power's ability to pay dividends on its common stock held by is limited to the extent payment of such dividends would violate the covenants in its credit facility or Idaho Power's Statement of Policy and Code of Conduct. A covenant under Idaho Power's credit facility requires Idaho Power to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization, as defined therein, of no more than 65 percent at the end of each fiscal quarter. At December 31, 2025, the leverage ratio for Idaho Power were 52 percent. Based on these restrictions, Idaho Power's dividends were limited to \$1.3 billion at December 31, 2025. There are additional facility covenants, subject to exceptions, that prohibit or restrict the sale or disposition of property without consent and any agreements restricting dividend payments to Idaho Power from any material subsidiary. At December 31, 2025, Idaho Power was in compliance with those covenants.

Idaho Power's Statement of Policy and Code of Conduct relating to transactions between and among Idaho Power, IDACORP, and other affiliates, which was approved by the IPUC in April 2008, provides that Idaho Power will not pay any dividends to IDACORP that will reduce Idaho Power's common equity capital below 35 percent of its total adjusted capital without IPUC approval. At December 31, 2025, Idaho Power's common equity capital was 48 percent of its total adjusted capital. Further, Idaho Power must obtain approval from the OPUC before it can directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

Idaho Power's articles of incorporation contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. As of the date of this report, Idaho Power has no preferred stock outstanding.

In addition to contractual restrictions on the amount and payment of dividends, the FPA prohibits the payment of dividends from "capital accounts." The term "capital account" is undefined in the FPA or its regulations, but Idaho Power does not believe the restriction would limit Idaho Power's ability to pay dividends out of current year earnings or retained earnings.

In accordance with Section 10(d) of the Federal Power Act, Idaho Power has \$13.3 million of amortization reserves established for certain of its licensed hydroelectric facilities.

7. SHARE-BASED COMPENSATION

Through its parent company IDACORP, Idaho Power has one share-based compensation plan — the 2000 Long-Term Incentive Compensation (LTICP). The LTICP (for officers, key employees, and directors) permits the grant of stock options, restricted stock and restricted stock units, performance shares and performance-based units, and several other types of share-based awards. At December 31, 2025, the maximum number of shares available under the LTICP was 1,119,104.

Restricted Stock Unit and Performance-Based Unit Awards

Restricted stock unit awards have three-year vesting periods, entitle the recipients to dividend equivalents, and units do not have voting rights until the units are vested and settled in shares. Unvested awards are restricted as to disposition and subject to forfeiture under certain circumstances. The fair value of these awards is based on the closing market price of common stock on the grant date and is charged to compensation expense over the vesting period, reduced for any forfeitures during the vesting period.

Performance-based unit awards have three-year vesting periods and do not have voting rights until the units are vested and settled in shares. Unvested awards are restricted as to disposition, subject to forfeiture under certain circumstances, and subject to the attainment of specific performance conditions over the three-year vesting period. The performance conditions are two equally-weighted metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. Depending on the level of attainment of the performance conditions and the year issued, the final number of shares awarded can range from zero to 200 percent of the target award. Dividend equivalents are accrued during the vesting period and paid out based on the final number of shares awarded.

The grant-date fair value of the CEPS portion is based on the closing market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments. The fair value of this portion of the awards is charged to compensation expense over the requisite service period based on the estimated achievement of performance targets, reduced for any forfeitures during the vesting period. The grant-date fair value of the TSR portion is estimated using the market value at the date of grant and a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The fair value of this portion of the awards is charged to compensation expense over the requisite service period, provided the requisite service period is rendered, regardless of the level of TSR metric attained.

A summary of restricted stock units and performance-based units award activity is presented below. Idaho Power unit amounts represent units of IDACORP:

	Number of Units	Weighted- Average Grant Date Fair Value
Nonvested units at January 1, 2025	233,577	\$ 94.73
Units granted	81,973	107.76
Units forfeited	(2,962)	94.28
Units vested	(65,116)	102.53
Nonvested units at December 31, 2025	247,472	\$ 97.00

The total fair value of shares vested was \$7.4 million in 2025 and \$8.5 million in 2024. At December 31, 2025, Idaho Power had \$11.5 million of total unrecognized compensation cost related to nonvested share-based compensation. These costs are expected to be recognized over a weighted-average period of 1.7 years. Original issue shares of IDACORP are used for these awards.

In 2025, a total of 11,268 shares of IDACORP common stock were awarded to directors of IDACORP and Idaho Power at an average grant date fair value of \$117.98 per share. Directors elected to defer receipt of 5,532 of these shares, which are being held as deferred stock units with dividend equivalents reinvested in additional stock units.

Compensation Expense: The following table shows Idaho Power's compensation cost recognized in income and the tax benefits resulting from the LTICP (in thousands of dollars):

	2025	2024
Compensation cost	\$ 12,419	\$ 11,608
Income tax benefit	3,108	2,988

No equity compensation costs have been capitalized. These costs are primarily reported within "Other operations and maintenance" expense on the statements of income.

8. COMMITMENTS

Purchase Obligations

At December 31, 2025, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2026	2027	2028	2029	2030	Thereafter
Cogeneration, power production, battery storage, and transmission rights	\$ 350,046	\$ 383,878	\$ 427,829	\$ 428,270	\$ 425,584	\$ 3,710,029
Fuel	191,035	159,806	96,773	45,314	46,063	498,929

As of December 31, 2025, Idaho Power had power purchase obligations with respect to 1,724 MW nameplate capacity of online PURPA and non-PURPA projects, with an additional

625 MW nameplate capacity of projects that are scheduled to be online in 2026 and 2027. The agreements for these projects range from one to 35 years. Idaho Power's purchased power expense associated with long-term agreements (including PURPA) was approximately \$306 million in 2025 and \$294 million in 2024.

Subsequent to December 31, 2025, through the date of this report, Idaho Power entered into an energy and capacity market purchase agreement with an energy marketer that provides Idaho Power the right to acquire 100 MW on a daily basis during the winter months, subject to regulatory approval, which increased Idaho Power's contractual obligations by approximately \$14.4 million over an approximate 3-year term commencing in November 2028.

Idaho Power also has the following long-term commitments (in thousands of dollars):

	2026	2027	2028	2029	2030	Thereafter
Joint-operating agreement payments ⁽¹⁾	\$ 2,983	\$ 2,983	\$ 2,983	\$ 2,983	\$ 2,983	\$ 14,914
Easements and other payments ⁽¹⁾	2,322	2,371	2,421	2,472	2,523	13,435
Maintenance, service, and materials agreements ⁽¹⁾⁽²⁾	479,388	110,347	312,155	36,558	8,327	41,237
FERC and other industry-related fees ⁽¹⁾	17,898	17,106	16,962	16,908	17,391	85,255

(1) Approximately \$30 million, \$1 million, \$16 million, and \$170 million of the commitments included in joint-operating agreement payments, easements and other payments, maintenance, service, and materials agreements, and FERC and other industry-related fees, respectively, have contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, ten years of information, estimated based on current contract terms, has been included in the table for presentation purposes.

(2) As of December 31, 2025, Idaho Power had a remaining \$481 million commitment related to contracts to acquire and own transmission and generation resources with in-service dates in 2028 and 2030.

Guarantees

Idaho Power guarantees its portion of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed annually with the Wyoming Department of Environmental Quality (WDEQ), was \$50.1 million at December 31, 2025, representing IERCo's one-third share of BCC's total reclamation obligation of \$150.2 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2025, the value of BCC's reclamation trust fund exceeded WDEQ's guarantee requirement for the total reclamation obligation. BCC periodically assesses the adequacy of the reclamation trust fund and its estimate of future reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, BCC has the ability to, and does, add a per-ton surcharge to coal sales to the Jim Bridger plant. Because of the existence of the fund and the ability to apply a per-ton surcharge, the estimated fair value of this guarantee is minimal.

Idaho Power enter into financial agreements and power purchase and sale agreements that include indemnification provisions relating to various forms of claims or liabilities that may arise from the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Idaho Power periodically evaluate the likelihood of incurring costs under such indemnities based on their historical experience and the evaluation of the specific indemnities. As of December 31, 2025, management believes the likelihood is remote that Idaho Power would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnification obligations. Idaho Power has not recorded any liability on its balance sheets with respect to these indemnification obligations.

9. LEASES

Recognition of Lease Assets and Liabilities

A lease exists when an arrangement allows the lessee to control the use of an identified asset for a stated period in exchange for payments. Idaho Power determines if an arrangement is a lease and its classification at the lease commencement date. All leases must be recognized as a lease right-of-use (ROU) asset and a lease liability on the balance sheet of the lessee. The ROU asset represents the right to use an underlying asset for the lease term, and lease liabilities represent the obligation to make lease payments. Idaho Power has elected the practical expedient to not separate non-lease components from lease components and instead account for both as a single lease component.

Lease ROU assets and lease liabilities are estimated and recognized at the lease commencement date based on the net present value of fixed lease payments over the lease term. Variable lease payments are expensed as incurred. If the lease does not provide an implicit rate, Idaho Power uses its collateralized incremental borrowing rate based on the information available at the commencement date to determine the present value of fixed lease payments. The implicit rate is used when it is readily determinable. Idaho Power recovers 100 percent of the Idaho-jurisdiction portion of lease payments on all existing arrangements classified as finance leases through the PCA, and recovers the Oregon-jurisdiction portion of lease payments through the APCU. Idaho Power recognizes lease expenses consistent with regulatory cost recovery, so lease expenses in excess of amounts recovered through the PCA and APCU are deferred as a regulatory asset.

Idaho Power does not record leases with a term of 12 months or less in the consolidated balance sheets. Total short-term lease expense was not material for the years ended 2025 and 2024.

Finance Leases

Finance leases are included in finance lease ROU assets, other current liabilities, and finance lease liabilities recognized on the consolidated balance sheets upon the lease commencement date. Amortization of the lease ROU asset is included in depreciation and amortization, and the interest expense associated with the finance lease liabilities is included in interest on long-term debt and finance leases on the consolidated statements of income. Variable lease payments are not recognized on the consolidated balance sheets and are recorded as incurred in other O&M expense on the consolidated statements of income and in operating activities in the consolidated statements of cash flows. Idaho Power's finance lease ROU assets and liabilities relate to the lease discussed below.

Kuna BESS: On April 26, 2023, Idaho Power executed an Energy Storage Agreement with Kuna BESS LLC to utilize the storage capacity of a 150 MW battery storage facility over a 20-year term. The term began May 19, 2025, and has been classified as a finance lease.

The following table provides a summary of the components of total lease cost included in the consolidated statements of income for the year ended December 31 (in thousands of dollars):

	2025
Finance lease cost:	
Amortization of ROU asset (Depreciation and amortization)	\$ 3,762
Interest on lease liabilities (Interest on long-term debt and finance leases) ⁽¹⁾	8,586
Total finance lease cost	12,348
Variable lease cost (Other O&M)	973
Total lease cost	\$ 13,321

(1) Included in operating activities in the consolidated statements of cash flows as cash paid for amounts included in the measurement of lease liabilities.

The following table presents the classification of certain lease amounts included in the consolidated balance sheets as of December 31 (in thousands of dollars):

	2025
Finance leases:	
Other current liabilities	\$ 6,161

The following table presents the weighted-average remaining lease term and weighted-average discount rate as of December 31:

	2025
Finance leases:	
Weighted average remaining lease term	19.38 years
Weighted average discount rate	6.17 %

The following table presents the maturities of future fixed lease payments and a reconciliation of undiscounted cash flows to lease liabilities recognized on the consolidated balance sheets as of December 31, 2025 (in thousands of dollars):

	Finance Leases
	\$
2026	19,751
2027	19,751
2028	19,751
2029	19,751
2030	19,751
Thereafter	283,907
Total future fixed lease payments	382,662
Less: amounts representing interest	(159,806)
Total present value of lease liabilities	222,856

10. CONTINGENCIES

Idaho Power has in the past and expect in the future to become involved in various claims, controversies, disputes, and other contingent matters, some of which involve litigation and regulatory or other contested proceedings. The ultimate resolution and outcome of litigation and regulatory proceedings is inherently difficult to determine, particularly where (a) the remedies or penalties sought are indeterminate, (b) the proceedings are in the early stages or the substantive issues have not been well developed, or (c) the matters involve complex or novel legal theories or a large number of parties. In accordance with applicable accounting guidance, Idaho Power, as applicable, establishes an accrual for legal proceedings when those matters proceed to a stage where they present loss contingencies that are both probable and reasonably estimable. If the loss contingency at issue is not both probable and reasonably estimable, Idaho Power does not establish an accrual and the matter will continue to be monitored for any developments that would make the loss contingency both probable and reasonably estimable. As of the date of this report, Idaho Power's accruals for loss contingencies are not material to their financial statements as a whole; however, future accruals could be material in a given period. Idaho Power's determination is based on currently available information, and estimates presented in financial statements and other financial disclosures involve significant judgment and may be subject to significant uncertainty. For matters that affect Idaho Power's operations, Idaho Power intends to seek, to the extent permissible and appropriate, recovery through the ratemaking process of costs incurred, although there is no assurance that such recovery would be granted.

Idaho Power is party to legal claims and legal, tax, and regulatory actions and proceedings in the ordinary course of business and, as noted above, record an accrual for associated loss contingencies when they are probable and reasonably estimable. In connection with its utility operations, Idaho Power is subject to claims by individuals, entities, and governmental agencies for damages for alleged personal injury, property damage, and economic losses, relating to the company's provision of electric service and the operation of its power supply, transmission, and distribution facilities. Some of those claims relate to electrical contacts, service quality, property damage, and wildfires. In recent years, utilities in the western United States have been subject to significant liability for personal injury, loss of life, property damage, trespass, and economic losses, and in some cases, punitive damages and criminal charges, associated with wildfires that originated from utility property, most commonly transmission and distribution lines. Idaho Power has also regularly received claims by governmental agencies and private landowners for damages for fires allegedly originating from Idaho Power's transmission and distribution system. As of the date of this report, Idaho Power believes that resolution of existing claims will not have a material adverse effect its financial statements.

Idaho Power is also actively monitoring various pending environmental regulations and executive orders related to environmental matters that may have a significant impact on its future operations. Given uncertainties regarding the outcome, timing, and compliance plans for these environmental matters, Idaho Power is unable to estimate the financial impact of these regulations.

11. BENEFIT PLANS

Idaho Power sponsors defined benefit and other postretirement benefit plans that cover the majority of its employees. Idaho Power also sponsors a defined contribution 401(k) employee savings plan and provides certain post-employment benefits.

Pension Plans

Idaho Power has a noncontributory defined benefit pension plan (pension plan) and two nonqualified defined benefit plans for certain senior management employees, the SMSP. Idaho Power also has a nonqualified defined benefit pension plan for directors that was frozen in 2002. Remaining vested benefits from that plan are included with the SMSP in the disclosures below. The benefits under these plans are based on years of service and the employee's final average earnings.

The following table summarizes the changes in benefit obligations and plan assets of these plans (in thousands of dollars):

	Pension Plan		SMSP	
	2025	2024	2025	2024
Change in projected benefit obligation:				
Benefit obligation at January 1	\$ 998,166	\$ 1,028,016	\$ 102,318	\$ 105,809
Service cost	31,774	33,992	1,172	1,051
Interest cost	56,151	52,181	5,640	5,332
Actuarial loss (gain)	5,237	(65,972)	2,401	(3,321)
Plan amendment	—	—	7	15
Benefits paid	(52,309)	(50,051)	(6,900)	(6,568)
Projected benefit obligation at December 31	1,039,019	998,166	104,638	102,318
Change in plan assets:				
Fair value at January 1	951,142	917,513	—	—
Actual return on plan assets	104,542	63,680	—	—
Employer contributions	20,000	20,000	—	—
Benefits paid	(52,309)	(50,051)	—	—
Fair value at December 31	1,023,375	951,142	—	—
Funded status at end of year	\$ (15,644)	\$ (47,024)	\$ (104,638)	\$ (102,318)
Amounts recognized in AOCI consist of:				
Net loss	\$ 13,142	\$ 43,516	\$ 18,154	\$ 16,442
Prior service cost	18	24	1,780	1,995
Subtotal	13,160	43,540	19,934	18,437
Less amount recorded as regulatory asset ⁽¹⁾	(13,160)	(43,540)	—	—
Net amount recognized in AOCI	\$ —	\$ —	\$ 19,934	\$ 18,437
Accumulated benefit obligation	\$ 895,190	\$ 863,705	\$ 99,105	\$ 96,487

(1) Changes in the funded status of the pension plan that would be recorded in AOCI for an unregulated entity are recorded as a regulatory asset for Idaho Power as Idaho Power believes it is probable that an amount equal to the regulatory asset will be collected through the setting of future rates.

The actuarial losses reflected in the benefit obligations for the pension and SMSP plans in 2025 are due primarily to actual demographic experience varying from assumed for both plans, and a decrease in the assumed discount rate of the SMSP plan and partially offset by an increase in the assumed discount rates of the pension plan from December 31, 2024 to December 31, 2025. The actuarial gains reflected in the benefit obligations for the pension and SMSP plans in 2024 are due primarily to increases in the assumed discount rates of both plans from December 31, 2023 to December 31, 2024. For more information on discount rates, see "Plan Assumptions" below in this Note 11.

As a non-qualified plan, the SMSP has no plan assets. However, Idaho Power has a rabbi trust designated to provide funding for SMSP obligations. The rabbi trust holds investments in marketable securities and corporate-owned life insurance. The recorded value of these investments was approximately \$172.1 million and \$159.1 million at December 31, 2025 and 2024, respectively.

The following table shows the components of net periodic pension cost for these plans (in thousands of dollars). For purposes of calculating the expected return on plan assets, the market-related value of assets is equal to the fair value of the assets.

	Pension Plan		SMSP	
	2025	2024	2025	2024
Service cost	\$ 31,774	\$ 33,992	\$ 1,172	\$ 1,051
Interest cost	56,151	52,181	5,640	5,332
Expected return on assets	(68,931)	(66,533)	—	—
Amortization of net loss	—	1,700	690	1,312
Amortization of prior service cost	6	6	221	220

Net periodic pension cost	19,000	21,346	7,723	7,915
Regulatory deferral of net periodic pension cost ⁽¹⁾	(18,159)	(20,425)	—	—
Previously deferred pension cost recognized ⁽¹⁾	35,182	35,182	—	—
Net periodic pension cost recognized for financial reporting ⁽¹⁾	\$ 36,023	\$ 36,103	\$ 7,723	\$ 7,915

(1) Net periodic pension costs for the pension plan are recognized for financial reporting based upon the authorization of each regulatory jurisdiction in which Idaho Power operates. Under an IPUC order, the Idaho portion of net periodic pension cost is recorded as a regulatory asset and is recognized in the income statement as those costs are recovered through rates.

The following table shows the components of other comprehensive income (loss) for the plans (in thousands of dollars):

	Pension Plan		SMSP	
	2025	2024	2025	2024
Actuarial gain (loss) during the year	\$ 30,374	\$ 63,119	\$ (2,401)	\$ 3,320
Plan amendment service cost	—	—	(7)	(15)
Reclassification adjustments for:				
Amortization of net loss	—	1,700	690	1,312
Amortization of prior service cost	6	6	221	220
Adjustment for deferred tax effects	(7,604)	(16,686)	145	(1,245)
Adjustment due to the effects of regulation	(22,776)	(48,139)	—	—
Other comprehensive income (loss) recognized related to pension benefit plans	\$ —	\$ —	\$ (1,352)	\$ 3,592

The following table summarizes the expected future benefit payments of these plans (in thousands of dollars):

	2026	2027	2028	2029	2030	2031-2035
Pension Plan	\$ 53,000	\$ 54,713	\$ 56,371	\$ 58,110	\$ 59,898	\$ 331,936
SMSP	6,855	6,883	7,079	7,360	7,438	37,939

Idaho Power's funding policy for the pension plan is to contribute at least the minimum required under the Employee Retirement Income Security Act of 1974 (ERISA) but not more than the maximum amount deductible for income tax purposes. In 2025 and 2024, Idaho Power elected to contribute more than the minimum required amounts in order to bring the pension plan to a more funded position, to reduce future required contributions, and to reduce Pension Benefit Guaranty Corporation premiums. As of the date of this report, Idaho Power have no estimated minimum required contributions to the pension plan for 2026. Depending on market conditions and cash flow considerations in 2025, Idaho Power expects that it may contribute up to \$30 million to the pension plan during 2026 in order to help balance the regulatory collection of these expenditures with the amount and timing of contributions and to mitigate the cost of being in an underfunded position.

Postretirement Benefits

Idaho Power maintains a defined benefit postretirement benefit plan (consisting of health care and death benefits) that covers all employees who were enrolled in the active-employee group plan at the time of retirement as well as their spouses and qualifying dependents. Retirees hired on or after January 1, 1999, have access to the standard medical option at full cost, with no contribution by Idaho Power. Benefits for employees who retire after December 31, 2002, are limited to a fixed amount, which has limited the growth of Idaho Power's future obligations under this plan.

The following table summarizes the changes in benefit obligation and plan assets (in thousands of dollars):

	2025	2024
Change in accumulated benefit obligation:		
Benefit obligation at January 1	\$ 54,604	\$ 56,064
Service cost	672	698
Interest cost	2,973	2,824
Actuarial loss (gain)	1,976	(778)
Benefits paid ⁽¹⁾	(4,714)	(4,204)
Benefit obligation at December 31	55,511	54,604
Change in plan assets:		
Fair value of plan assets at January 1	31,128	31,804
Actual return on plan assets	4,381	4,669
Employer contributions ⁽¹⁾	736	(1,141)
Benefits paid ⁽¹⁾	(4,714)	(4,204)

Fair value of plan assets at December 31

	31,531	31,128
Funded status at end of year	\$ (23,980)	\$ (23,476)

(1) Contributions and benefits paid are each net of \$2.3 million and \$2.3 million of plan participant contributions for 2025 and 2024, respectively.

Amounts recognized in AOCI consist of the following (in thousands of dollars):

	2025	2024
Net gain	\$ (28,207)	\$ (29,353)
Prior service cost	3,262	4,636
Subtotal	(24,945)	(24,717)
Less amount recognized in regulatory assets	24,945	24,717
Net amount recognized in AOCI	\$ —	\$ —

The net periodic postretirement benefit cost was as follows (in thousands of dollars):

	2025	2024
Service cost	\$ 672	\$ 698
Interest cost	2,973	2,824
Expected return on plan assets	(1,786)	(1,831)
Amortization of net loss	(1,765)	(1,494)
Amortization of prior service cost	1,374	1,548
Net periodic postretirement benefit cost	\$ 1,468	\$ 1,745

The following table shows the components of other comprehensive income for the plan (in thousands of dollars):

	2025	2024
Actuarial gain during the year	\$ 619	\$ 3,616
Reclassification adjustments for:		
Amortization of net loss	(1,765)	(1,494)
Amortization of prior service cost	1,375	1,548
Adjustment for deferred tax effects	(57)	(945)
Adjustment due to the effects of regulation	(172)	(2,725)
Other comprehensive income related to postretirement benefit plans	\$ —	\$ —

The following table summarizes the expected future benefit payments of the postretirement benefit plan (in thousands of dollars):

	2026	2027	2028	2029	2030	2031-2035
Expected benefit payments	\$ 4,855	\$ 4,715	\$ 4,620	\$ 4,580	\$ 4,511	\$ 21,157

Plan Assumptions

The following table sets forth the weighted-average assumptions used at the end of each year to determine benefit obligations for all Idaho Power-sponsored pension and postretirement benefits plans:

	Postretirement					
	Pension Plan		SMSP		Benefits	
	2025	2024	2025	2024	2025	2024
Discount rate	5.75 %	5.70 %	5.65 %	5.70 %	5.60 %	5.70 %
Rate of compensation increase ⁽¹⁾	4.42 %	4.43 %	4.75 %	4.75 %	—	—
Medical trend rate	—	—	—	—	7.0 %	6.3 %
Dental trend rate	—	—	—	—	4.0 %	3.5 %
Measurement date	12/31/2025	12/31/2024	12/31/2025	12/31/2024	12/31/2025	12/31/2024

(1) The 2025 rate of compensation increase assumption for the pension plan includes an inflation component of 2.40% plus a 2.02% composite merit increase component that is based on employees' years of service. Merit salary increases are assumed to be 10.6% for employees in their first year of service and scale down to 3.4% for employees in their fortieth year of service and beyond.

The following table sets forth the weighted-average assumptions used to determine net periodic benefit cost for all Idaho Power-sponsored pension and postretirement benefit plans:

	Postretirement					
	Pension Plan		SMSP		Benefits	
	2025	2024	2025	2024	2025	2024
Discount rate	5.70 %	5.10 %	5.70 %	5.20 %	5.70 %	5.15 %
Expected long-term rate of return on assets	7.40 %	7.40 %	—	—	6.00 %	6.00 %
Rate of compensation increase	4.42 %	4.43 %	4.75 %	4.75 %	—	— %
Medical trend rate	—	—	—	—	6.2 %	7.1 %
Dental trend rate	—	—	—	—	4.0 %	3.5 %

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 6.2 percent in 2025 and is assumed to increase to 7.0 percent in 2026, decrease to 6.2 percent in 2027, decrease to 5.5 percent in 2028, and to gradually decrease to 3.8 percent by 2074. For 2025 and beyond, the assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 4.0 percent, or equal to the medical trend rate if lower.

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2025, for the pension asset portfolio by asset class is set forth below:

Asset Class	Target	Actual
	Allocation	December 31, 2025
Debt securities	25 %	25 %
Equity securities	56 %	59 %
Real estate	8 %	8 %
Other plan assets	11 %	8 %
Total	100 %	100 %

Assets are rebalanced as necessary to keep the portfolio close to target allocations. The plan's principal investment objective is to maximize total return (defined as the sum of realized interest and dividend income and realized and unrealized gain or loss in market price) consistent with prudent parameters of risk and the liability profile of the portfolio. Emphasis is placed on preservation and growth of capital along with adequacy of cash flow sufficient to fund current and future payments to plan participants.

The three major goals in Idaho Power's asset allocation process are to:

- determine if the investments have the potential to earn the rate of return assumed in the actuarial liability calculations;
- match the cash flow needs of the plan. Idaho Power sets debt security allocations sufficient to cover approximately five years of benefit payments. Idaho Power then utilizes growth instruments (equities, real estate, venture capital) to fund the longer-term liabilities of the plan; and
- maintain a prudent risk profile consistent with ERISA fiduciary standards.

Allowable plan investments include stocks and stock funds, investment-grade bonds and bond funds, private real estate funds, private infrastructure funds, private direct lending funds, private equity funds, and cash and cash equivalents. With the exception of private real estate holdings, private infrastructure holdings, private direct lending loans, and private equity, investments must be readily marketable so that an entire holding can be disposed of quickly with only a minor effect upon market price.

Rate-of-return projections for plan assets are based on historical risk/return relationships among asset classes. The primary measure is the historical risk premium each asset class has delivered versus the yield on the Moody's AA Corporate Bond Index. This historical risk premium is then added to the current yield on the Moody's AA Corporate Bond Index. Additional analysis is performed to measure the expected range of returns, as well as worst-case and best-case scenarios. Based on the current interest rate environment, current rate-of-return expectations are lower than the nominal returns generated over the past 30 years when interest rates were generally higher.

Idaho Power's asset modeling process also utilizes historical market returns to measure the portfolio's exposure to a "worst-case" market scenario, to determine how much performance could vary from the expected "average" performance over various time periods. This "worst-case" modeling, in addition to cash flow matching and diversification by asset class and investment style, provides the basis for managing the risk associated with investing portfolio assets.

Fair Value of Plan Assets: Idaho Power classifies its pension plan and postretirement benefit plan investments using the three-level fair value hierarchy described in Note 16 - "Fair Value Measurements." The following table presents the fair value of the plans' investments by asset category (in thousands of dollars).

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2025				
Cash and cash equivalents	\$ 11,625	\$ —	\$ —	\$ 11,625
Intermediate bonds	42,326	204,129	—	246,455
Equity Securities: Large-Cap	54,168	—	—	54,168

Equity Securities: Mid-Cap	106,437	—	—	106,437
Equity Securities: Small-Cap	85,047	—	—	85,047
Equity Securities: Micro-Cap	43,752	—	—	43,752
Equity Securities: Global and International	63,998	—	—	63,998
Equity Securities: Emerging Markets	3,433	—	—	3,433
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Commingled Fund: Equity Securities: Large-Cap				52,830
Commingled Fund: Equity Securities: Global and International				146,047
Commingled Fund: Equity Securities: Emerging Markets				52,305
Direct Lending Fund: Fixed Income				8,377
Real estate				77,141
Other Private market investments				71,760
Total	\$ 410,786	\$ 204,129	\$ —	\$ 1,023,375
Postretirement plan assets ⁽¹⁾	\$ 1,224	\$ 30,307	\$ —	\$ 31,531

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2024				
Cash and cash equivalents	\$ 24,946	\$ —	\$ —	\$ 24,946
Intermediate bonds	40,177	184,528	—	224,705
Equity Securities: Large-Cap	49,848	—	—	49,848
Equity Securities: Mid-Cap	103,117	—	—	103,117
Equity Securities: Small-Cap	82,932	—	—	82,932
Equity Securities: Micro-Cap	38,871	—	—	38,871
Equity Securities: Global and International	58,767	—	—	58,767
Equity Securities: Emerging Markets	6,093	—	—	6,093
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Commingled Fund: Equity Securities: Large-Cap				54,346
Commingled Fund: Equity Securities: Global and International				124,559
Commingled Fund: Equity Securities: Emerging Markets				41,590
Direct Lending Fund: Fixed Income				5,479
Real estate				72,913
Other Private market investments				62,976
Total	\$ 404,751	\$ 184,528	\$ —	\$ 951,142
Postretirement plan assets ⁽¹⁾	\$ 3,054	\$ 28,074	\$ —	\$ 31,128

(1) The postretirement benefits assets are primarily life insurance contracts.

For the years ended December 31, 2025 and 2024, there were no material transfers into or out of Levels 1, 2, or 3.

Fair Value Measurement of Level 2 Plan assets and Plan assets measured at NAV:

Level 2 Bonds: These investments represent United States government, agency bonds, and corporate bonds. The United States government and agency bonds, as well as the corporate bonds, are not traded on an exchange and are valued utilizing market prices for similar assets or liabilities in active markets.

Level 2 Postretirement Asset: This asset represents an investment in a life insurance contract and is recorded at fair value, which is the cash surrender value, less any unpaid expenses. The cash surrender value of this insurance contract is contractually equal to the insurance contract's proportionate share of the market value of an associated investment account held by the insurer. The investments held by the insurer's investment account are all instruments traded on exchanges with readily determinable market prices.

Commingled Funds: These funds, made up of global, international and emerging markets equity securities are measured at NAV, are not publicly traded, and therefore no publicly quoted market price is readily available. The values of the commingled funds are presented at estimated fair value, which is determined based on the unit value of the fund. The values of these investments are calculated by the custodian for the fund company on a monthly or more frequent basis, and are based on market prices of the assets held by each of the commingled funds divided by the number of fund shares outstanding for the respective fund. The investments in commingled funds have redemption limitations that permit monthly redemption following notice requirements of 1 to 15 days.

Direct Lending Funds: Direct lending strategies are closed-end funds that provide senior secured loans primarily to private, non-investment-grade companies. Direct lending fund investments are valued by the fund companies, or an independent external advisor, based on the estimated fair value of the underlying loans divided by the fund shares outstanding. These direct lending funds also furnish annual audited financial statements that are used to further validate the information provided. These closed-end funds are formed with a stated life of 6 to 10 years, which can be further extended with the approval of the limited partners. There are generally no redemption rights associated with these funds. The limited partner must hold the fund for the life of the fund or find a third-party buyer.

Real Estate: Real estate holdings represent investments in open-end and closed-end commingled real estate funds. As the property interests held in these real estate funds are not frequently traded, establishing the market value of the property interests held by the fund, and the resulting unit value of fund shareholders, is based on unobservable inputs including property appraisals by the fund companies, property appraisals by independent appraisal firms, analysis of the replacement cost of the property, discounted cash flows generated by property rents and changes in property values, and comparisons with sale prices of similar properties in similar markets. These real estate funds also furnish annual audited financial statements that are also used to further validate the information provided. Redemptions on the open-end funds are generally available on a quarterly basis, with 10 to 35 days written notice, depending on the individual fund. If the fund has sufficient liquidity, the redemption will be processed at the fund NAV or the fund's estimate of fair value at the end of the

quarter. If the fund does not have sufficient liquidity to honor the full redemption, the remainder will be set for redemption the following quarter on a pro-rata basis with other redemption requests. This same process will repeat until the redemption request has been completed. To protect other fund holders, real estate funds have no duty to liquidate or encumber funds to meet redemption requests. The closed-end funds are formed for a stated life of 7 to 10 years. The fund can be further extended with the approval of the limited partners. There are generally no redemption rights associated with these funds. The limited partner must hold the fund for the life of the fund or find a third-party buyer.

Other Private Market Investments: Private market investments represent three categories: venture capital funds, private infrastructure funds, and fund of hedge funds. These funds are valued by the fund companies based on the estimated fair values of the underlying fund holdings divided by the fund shares outstanding or multiplied by the ownership percentages of the holder. Venture capital fund investments are valued by the fund companies based on estimated fair value of the underlying fund holdings divided by the fund shares outstanding. Some venture capital investments have progressed to the point that they have readily available exchange-based market valuations. Early stage venture investments are valued based on unobservable inputs including cost, operating results, discounted cash flows, the price of recent funding events, or pending offers from other viable entities. These private market investments furnish annual audited financial statements that are also used to further validate the information provided. These funds are formed for a stated life of 10 to 15 years. The general partner can extend the fund life for 2 or 3 one-year periods. The fund can be further extended with the approval of the limited partners. There are generally no redemption rights associated with these funds. The limited partner must hold the fund for the life of the fund or find a third-party buyer. The private infrastructure fund investment is valued by the fund manager through a process involving an independent third-party external valuator on a quarterly basis, with each investment undergoing a full independent valuation at least once per year. Redemption on the infrastructure fund are available on a quarterly basis beginning in April of 2027 with 90 days written notice. If the fund has sufficient liquidity, the redemption will be processed at the fund NAV at the end of the quarter. If the fund does not have sufficient liquidity to honor the full redemption, the remainder will be set for redemption the following quarter on a pro-rata basis with other redemption requests. This same process will repeat until the redemption request has been completed. The value of the fund of hedge funds investment is the residual value of an immaterial non-liquid position in a single fund of hedge funds.

Employee Savings Plan

Idaho Power has a defined contribution plan designed to comply with Section 401(k) of the Internal Revenue Code and that covers substantially all employees. Idaho Power matches specified percentages of employee contributions to the plan. Matching annual contributions were approximately \$10.9 million and \$10.4 million in 2025 and 2024, respectively.

Post-employment Benefits

Idaho Power provides certain benefits to former or inactive employees, their beneficiaries, and covered dependents after employment but before retirement, in addition to the health care benefits required under the Consolidated Omnibus Budget Reconciliation Act. These benefits include salary continuation, health care and life insurance for those employees found to be disabled under Idaho Power's disability plans, and health care for surviving spouses and dependents. Idaho Power accrues a liability for such benefits. The post-employment benefits included on Idaho Power's balance sheets at December 31, 2025 and 2024, were approximately \$1 million and \$3 million, respectively.

12. PROPERTY, PLANT AND EQUIPMENT AND JOINTLY-OWNED PROJECTS

The following table presents the major classifications of Idaho Power's utility plant in service, annual depreciation provisions as a percent of average depreciable balance, and accumulated provision for depreciation for the years ended December 31 (in thousands of dollars):

	2025		2024	
	Balance	Avg Rate	Balance	Avg Rate
Production	\$ 2,675,671	4.02 %	\$ 2,858,678	3.90 %
Transmission	1,653,490	1.91 %	1,534,474	1.89 %
Energy Storage ⁽¹⁾	509,740	5.06 %	393,012	3.61 %
Distribution ⁽¹⁾	2,658,849	2.17 %	2,465,423	2.16 %
Finance lease right-of-use assets	219,612	5.00 %	—	— %
General and Other	779,409	5.27 %	723,690	5.18 %
Total in service	8,496,771	3.18 %	7,975,277	3.06 %
Accumulated provision for depreciation	(2,763,239)		(2,881,560)	
In service - net	\$ 5,733,532		\$ 5,093,717	

(1) The presentation of the major classifications of Idaho Power's utility plant in service in the table above has been modified to separately report the energy storage balance for the years ended December 31, 2025 and 2024. The prior year energy storage balance, which had previously been classified in the distribution balance, has been reclassified to conform with the current year presentation. This change reflects a shift from one acceptable presentation to another to enhance transparency.

At December 31, 2025, Idaho Power's construction work in progress balance of \$1.7 billion including relicensing costs of \$536.1 million for the HCC, Idaho Power's largest hydropower complex. The IPUC allows Idaho Power to collect a portion of AFUDC relating to the HCC relicensing project in its Idaho jurisdiction rates. For more information, refer to Note 3 - "Regulatory Matters." Collecting these amounts will reduce the amount collected in the future once the HCC relicensing costs are approved for recovery in base rates. At December 31, 2025, Idaho Power's provision for rate refund for collection of AFUDC relating to the HCC was \$281.0 million.

Idaho Power's ownership interest in two jointly-owned generating facilities is included in the table above. Under the joint operating agreements for these facilities, each participating utility is responsible for financing its share of construction, operating, and leasing costs. Idaho Power's proportionate share of operating expenses for each facility is included in the statements of income. These jointly-owned facilities, including balance sheet amounts and the extent of Idaho Power's participation, were as follows at December 31, 2025 (in thousands of dollars):

Name of Plant	Location	Utility Plant in Service	Construction	Accumulated	Ownership %	MW ⁽¹⁾⁽²⁾
			Work in Progress	Provision for Depreciation		
Jim Bridger units 1-4	Rock Springs, WY	\$ 777,096	\$ 780	\$ 575,151	33	775
North Valmy units 1 & 2 ⁽²⁾	Winnemucca, NV	42,113	21,118	(128)	50	284

(1) Idaho Power's share of nameplate capacity.

(2) Pursuant to an agreement with NV Enerov, Idaho Power ceased participation in coal-fired operations of North Valmy in December 2019 at unit 1 and December 2025 at unit 2. Idaho Power's 2025 IRP identified a preferred

IERCO, Idaho Power's wholly-owned subsidiary, is a joint-owner of BCC. Idaho Power's coal purchases from BCC were \$54.4 million in 2025 and \$51.6 million in 2024.

13. ASSET RETIREMENT OBLIGATIONS (ARO)

The guidance relating to accounting for AROs requires that legal obligations associated with the retirement of property, plant, and equipment be recognized as a liability at fair value when incurred and when a reasonable estimate of the fair value of the liability can be made. Under the guidance, when a liability is initially recorded, the entity increases the carrying amount of the related long-lived asset to reflect the future retirement cost. Over time, the liability is accreted to its estimated settlement value and paid, and the capitalized cost is depreciated over the useful life of the related asset. If, at the end of the asset's life, the recorded liability differs from the actual obligations paid, a gain or loss would be recognized. As a rate-regulated entity, Idaho Power defers accretion, depreciation, and gains or losses as regulatory assets, as approved by the IPUC, until such ARO costs are included in customer rates for collection. The regulatory assets recorded under this order do not earn a return on investment.

Idaho Power's recorded AROs relate to the reclamation and removal costs at its jointly-owned thermal generation facilities. In 2025, changes in estimates at the jointly-owned thermal generation facilities resulted in a net increase of \$21.6 million in the recorded AROs. The increase is primarily related to updated post-closure cost estimates for a flue gas desulfurization pond at the Jim Bridger plant which was retired in December 2025.

Idaho Power also has additional AROs associated with its transmission system and generation facilities; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the financial statements.

Idaho Power also collects removal costs in rates for certain assets that do not have associated AROs. Idaho Power is required to classify these removal costs as regulatory liabilities, see Note 3 - "Regulatory Matters" for the removal costs recorded as regulatory liabilities on Idaho Power's balance sheets as of December 31, 2025 and 2024.

The following table presents the changes in the carrying amount of AROs (in thousands of dollars):

	2025	2024
Balance at January 1	\$ 51,126	\$ 48,997
Accretion expense	2,457	1,895
Revisions in estimated cash flows	21,642	842
Liability settled	(1,249)	(608)
Balance at December 31	\$ 73,976	\$ 51,126

14. INVESTMENTS

The table below summarizes Idaho Power's investments as of December 31 (in thousands of dollars):

	2025	2024
Idaho Power investments:		
IERCO	\$ 26,625	\$ 24,377
Exchange traded short-term bond funds and cash equivalents	37,232	38,873
Held-to-maturity securities	33,822	32,151
Executive deferred compensation plan investments	1,216	899
Total Idaho Power investments	\$ 98,895	\$ 96,300

Investments in Equity Securities

Investments in equity securities are reported at fair value. Any unrealized gains or losses on equity securities are included in income. Unrealized gains and losses on equity securities were immaterial at December 31, 2025 and 2024. There were no gross realized gains or losses from the sale of equity securities in 2025 and 2024.

Held-to-Maturity Securities

Idaho Power has a rabbi trust designated to provide funding for obligations related to the SMSF. During 2025 and 2024, the rabbi trust purchased \$2.9 million and \$1.8 million, respectively of held-to-maturity investments in corporate fixed-income and asset-backed debt securities. Substantially all of these debt securities mature between 2027 and 2037. Held-to-maturity investments are carried at amortized cost, reflecting Idaho Power's ability and intent to hold the securities to maturity. Held-to-maturity investments are adjusted for the amortization or accretion of premiums or discounts, which are amortized or accreted over the life of the related held-to-maturity security. Such amortization and accretion are included

in the statements of income. Due to increases in market interest rates in 2025 and 2024, all held-to-maturity securities were in a gross unrealized holding loss position totaling \$1.4 million and \$2.7 million at December 31, 2025 and 2024, respectively. Based on ongoing credit evaluations of these holdings, Idaho Power does not expect material payment defaults or delinquencies and has not recorded an allowance for credit losses for these securities as of December 31, 2025 and 2024.

15. DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Price Risk

Idaho Power is exposed to market risk relating to electricity, natural gas, and other fuel commodity prices, all of which are heavily influenced by supply and demand. Market risk may be influenced by market participants' nonperformance of their contractual obligations and commitments, which affects the supply of or demand for the commodity. Idaho Power uses derivative instruments, such as physical and financial forward contracts, for both electricity and fuel to manage the risks relating to these commodity price exposures. The primary objectives of Idaho Power's energy purchase and sale activity are to meet the demand of retail electric customers, maintain appropriate physical reserves to ensure reliability, and make economic use of temporary surpluses that may develop.

All of Idaho Power's derivative instruments have been entered into for the purpose of securing energy resources for future periods or economically hedging forecasted purchases and sales, though none of these instruments have been designated as cash flow hedges. Idaho Power offsets fair value amounts recognized on its balance sheet and applies collateral related to derivative instruments executed with the same counterparty under the same master netting agreement. Idaho Power does not offset a counterparty's current derivative contracts with the counterparty's long-term derivative contracts, although Idaho Power's master netting arrangements would allow current and long-term positions to be offset in the event of default. Also, in the event of default, Idaho Power's master netting arrangements would allow for the offsetting of all transactions executed under the master netting arrangement. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral (such as letters of credit). These types of transactions are excluded from the offsetting presented in the derivative fair value and offsetting table that follows.

The table below presents the gains and losses on derivatives not designated as hedging instruments for the years ended December 31 (in thousands of dollars):

	Location of Realized Gain/(Loss) on Derivatives Recognized in Income	Gain/(Loss) on Derivatives Recognized in Income ⁽¹⁾	
		2025	2024
Financial swaps	Operating revenues	\$ 559	\$ 5,189
Financial swaps	Purchased power	(3,967)	(7,101)
Financial swaps	Fuel expense	(37,659)	(63,380)
Forward contracts	Operating revenues	917	1,885
Forward contracts	Purchased power	(1,017)	(3,742)
Forward contracts	Fuel expense	(1,457)	(2,510)

(1) Excludes unrealized gains or losses on derivatives, which are recorded on the balance sheet as regulatory assets or regulatory liabilities.

Settlement gains and losses on electricity swap contracts are recorded on the income statement in operating revenues or purchased power depending on the forecasted position being economically hedged by the derivative contract. Settlement gains and losses on contracts for natural gas are reflected in fuel expense. Settlement gains and losses on diesel derivatives are recorded in other O&M expense. See Note 16 - "Fair Value Measurements" for additional information concerning the determination of fair value for Idaho Power's assets and liabilities from price risk management activities.

Credit Risk

At December 31, 2025, Idaho Power did not have material credit risk exposure from financial instruments, including derivatives. Idaho Power monitors credit risk exposure through reviews of counterparty credit quality, corporate-wide counterparty credit exposure, and corporate-wide counterparty concentration levels. Idaho Power manages these risks by establishing credit and concentration limits on transactions with counterparties and requiring contractual guarantees, cash deposits, bonds, or letters of credit from counterparties or their affiliates, as deemed necessary. Idaho Power's physical power contracts are commonly under WSPP, Inc. agreements, physical gas contracts are usually under North American Energy Standards Board contracts, and financial transactions are usually under International Swaps and Derivatives Association, Inc. contracts. These contracts typically contain adequate assurance clauses requiring collateralization if a counterparty has debt that is downgraded below investment grade by at least one rating agency.

Credit-Contingent Features

Certain of Idaho Power's derivative instruments contain provisions that require Idaho Power's unsecured debt to maintain an investment grade credit rating from Moody's and Standard & Poor's Ratings Services. If Idaho Power's unsecured debt were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position at December 31, 2025, was \$55.8 million. As of December 31, 2025, Idaho Power posted \$45.1 million of cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2025, Idaho Power would have been required to pay or post collateral to its counterparties up to an additional \$34.0 million to cover open liability positions as well as completed transactions that have not yet been paid.

Derivative Instrument Summary

The table below presents the fair values and locations or derivative instruments not designated as hedging instruments recorded on the balance sheets and reconciles the gross amounts of derivatives recognized as assets and as liabilities to the net amounts presented in the balance sheets (in thousands of dollars):

	Balance Sheet Location	Asset Derivatives			Liability Derivatives		
		Gross Fair Value	Amounts Offset	Net Assets	Gross Fair Value	Amounts Offset	Net Liabilities
December 31, 2025							
Current:							
Financial swaps	Other current liabilities	2,535	(2,535)	—	34,486	(29,394) ⁽¹⁾	5,092
Forward contracts	Other current assets	3	—	3	—	—	—
Forward contracts	Other current liabilities	—	—	—	1,009	—	1,009
Long-term:							
Financial swaps	Other liabilities	1,444	(1,444)	—	7,479	(4,385) ⁽²⁾	3,094
Forward contracts	Other liabilities	—	—	—	10,524	—	10,524
Total		\$ 3,982	\$ (3,979)	\$ 3	\$ 53,498	\$ (33,779)	\$ 19,719

December 31, 2024							
Current:							
Financial swaps	Other current liabilities	3,072	(3,072)	—	18,092	(14,931) ⁽³⁾	3,161
Forward contracts	Other current liabilities	—	—	—	1,291	—	1,291
Long-term:							
Financial swaps	Other assets	1,939	(1,939) ⁽⁴⁾	—	409	(409)	—
Financial swaps	Other liabilities	177	(177)	—	1,019	(177)	842
Forward contracts	Other liabilities	—	—	—	10,965	—	10,965
Total		\$ 5,188	\$ (5,188)	\$ —	\$ 31,776	\$ (15,517)	\$ 16,259

(1) Current liability derivative amounts offset include \$26.9 million of collateral receivable at December 31, 2025.

(2) Long-term liability derivative amounts offset include \$2.9 million of collateral receivable at December 31, 2025.

(3) Current liability derivative amounts offset include \$11.9 million of collateral receivable at December 31, 2024.

(4) Long-term asset derivative amounts offset include \$1.5 million of collateral payable at December 31, 2024.

The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at December 31 (in thousands of units):

Commodity	Units	2025	2024
Electricity purchases	MWh	200	161
Electricity sales	MWh	33	16
Natural gas purchases	MMBtu	131,863	88,330

16. FAIR VALUE MEASUREMENTS

Idaho Power have categorized their financial instruments into a three-level fair value hierarchy, based on the priority of the inputs to the valuation technique. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). If the inputs used to measure the financial instruments fall within different levels of the hierarchy, the categorization is based on the lowest level input that is significant to the fair value measurement of the instrument.

Financial assets and liabilities recorded on the consolidated balance sheets are categorized based on the inputs to the valuation techniques as follows:

- Level 1: Financial assets and liabilities whose values are based on unadjusted quoted prices for identical assets or liabilities in an active market that Idaho Power have the ability to access.
- Level 2: Financial assets and liabilities whose values are based on the following:
 - a) quoted prices for similar assets or liabilities in active markets;
 - b) quoted prices for identical or similar assets or liabilities in non-active markets;
 - c) pricing models whose inputs are observable for substantially the full term of the asset or liability; and
 - d) pricing models whose inputs are derived principally from or corroborated by observable market data through correlation or other means for substantially the full term of the asset or liability.

Idaho Power Level 2 inputs for derivative instruments are based on quoted market prices adjusted for location using corroborated, observable market data or using quoted price which may be in non-active markets.

- Level 3: Financial assets and liabilities whose values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. These inputs reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Idaho Power's assessment of a particular input's significance to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. There were no transfers between levels or material changes in valuation techniques or inputs during the years ended December 31, 2025 and 2024.

The following table presents information about Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31 (in thousands of dollars):

	2025				2024			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Money market funds and commercial paper	110,602	—	—	110,602	158,999	—	—	158,999
Derivatives	—	3	—	3	—	—	—	—
Equity securities	38,448	—	—	38,448	39,772	—	—	39,772
Liabilities:								
Derivatives	\$ 8,186	\$ 11,533	\$ —	\$ 19,719	\$ 4,003	\$ 12,256	\$ —	\$ 16,259

Idaho Power's derivatives are contracts entered into as part of its management of loads and resources. Electricity swap derivatives are valued on the Intercontinental Exchange (ICE) with quoted prices in an active market. Electricity forward contract derivatives are valued using a blend of two electricity exchanges, adjusted for location basis, as specified in the forward contract. Natural gas and diesel derivatives are valued using New York Mercantile Exchange (NYMEX) and ICE pricing, adjusted for location basis, which are also quoted under NYMEX and ICE pricing. Equity securities at Idaho Power consist of employee-directed investments related to an executive deferred compensation plan and actively traded money market and exchange traded funds related to the SMSP. The investments are measured using quoted prices in active markets and are held in a rabbi trust.

The table below presents the carrying value and estimated fair value of financial instruments that are not reported at fair value, as of December 31, using available market information and appropriate valuation methodologies (in thousands of dollars).

	2025		2024	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Assets:				
Held-to-maturity securities ⁽¹⁾	\$ 33,822	\$ 32,468	\$ 32,151	\$ 29,428
Liabilities:				
Long-term debt (including current portion) ⁽¹⁾	3,447,338	3,270,200	3,073,662	2,807,803

(1) Held-to-maturity securities and long-term debt are categorized as Level 2 of the fair value hierarchy, as defined earlier in this Note 16 - "Fair Value Measurements."

Held-to-maturity securities are held in a rabbi trust and are generally valued using quoted prices, which may be in non-active markets. Long-term debt is not traded on an exchange and is valued using quoted rates for similar debt in active markets. Carrying values for cash and cash equivalents, deposits, customer and other receivables, notes payable, accounts payable, interest accrued, and taxes accrued approximate fair value.

17. CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

Comprehensive income includes net income and amounts related to the SMSP. The table below presents changes in components of AOCI, net of tax, during the years ended December 31 (in thousands of dollars). Items in parentheses indicate reductions to AOCI.

	2025	2024
Defined benefit pension items		
Balance at beginning of period	\$ (13,592)	\$ (17,184)
Other comprehensive income before reclassifications, net of tax of \$(374) and \$851	(2,034)	2,454
Amounts reclassified out of AOCI to net income, net of tax of \$229 and \$394	682	1,138
Net current-period other comprehensive income	(1,352)	3,592
Balance at end of period	\$ (14,944)	\$ (13,592)

The table below presents the effects on net income of amounts reclassified out of components of AOCI and the income statement location of those amounts reclassified during the years ended December 31 (in thousands of dollars). Items in parentheses indicate increases to net income.

	Amount Reclassified from AOCI	
	2025	2024
Amortization of defined benefit pension items		
Prior service cost	\$ 221	\$ 220
Net loss	600	1,212

Net loss	890	1,512
Total before tax	911	1,532
Tax benefit	(229)	(394)
Net of tax	682	1,138
Total reclassification for the period	\$ 682	\$ 1,138

18. RELATED PARTY TRANSACTIONS

IDACORP: Idaho Power performs corporate functions such as financial, legal, and management services for IDACORP and its subsidiaries. Idaho Power charges IDACORP for the costs of these services based on service agreements and other specifically identified costs. For these services, Idaho Power billed IDACORP \$1.5 million in 2025 and \$1.1 million in 2024.

At December 31, 2025 and 2024, Idaho Power had a \$3.3 million and \$3.2 million payable to IDACORP, respectively, which was included in its accounts payable to affiliates balance on its balance sheets.

Ida-West: Ida-West Energy Company (Ida-West) is a wholly-owned subsidiary of IDACORP and is an operator of small PURPA-qualifying hydropower generation projects. Idaho Power purchases all of the power generated by four of Ida-West's 50 percent owned PURPA-qualifying hydropower projects located in Idaho. Idaho Power purchased \$9.5 million in 2025 and \$9.6 million in 2024 of power from Ida-West.

19. SALE OF OREGON ASSETS

On February 13, 2026, Idaho Power executed a definitive agreement to sell its Oregon electric distribution business as well as certain Oregon transmission assets to OTEC. The base purchase price to be paid by OTEC for the Oregon Sale is \$154 million, and is subject to certain adjustments at the closing of the transaction. Idaho Power has agreed to operate its Oregon electric distribution business and applicable transmission assets in the ordinary course of business and subject to certain operating covenants during the period between the date of the asset purchase agreement and the completion of the proposed transaction. The Oregon Sale is subject to various closing conditions, including approvals of the OPUC, IPUC, and FERC, as well as certain price adjustment and termination provisions. Any gain or loss resulting from the Oregon Sale is expected to be immaterial to the financial statements of Idaho Power.

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)
1	Balance of Account 219 at Beginning of Preceding Year				(17,184,492)	
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				1,137,540	
3	Preceding Quarter/Year to Date Changes in Fair Value				2,454,718	
4	Total (lines 2 and 3)				3,592,258	
5	Balance of Account 219 at End of Preceding Quarter/Year				(13,592,234)	
6	Balance of Account 219 at Beginning of Current Year				(13,592,234)	
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				681,717	
8	Current Quarter/Year to Date Changes in Fair Value				(2,033,959)	
9	Total (lines 7 and 8)				(1,352,242)	
10	Balance of Account 219 at End of Current Quarter/Year				(14,944,476)	

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)	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		(17,184,492)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income		1,137,540		
3	Preceding Quarter/Year to Date Changes in Fair Value		2,454,718		
4	Total (lines 2 and 3)		3,592,258	280,604,710	284,196,968
5	Balance of Account 219 at End of Preceding Quarter/Year		(13,592,234)		
6	Balance of Account 219 at Beginning of Current Year		(13,592,234)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income		681,717		
8	Current Quarter/Year to Date Changes in Fair Value		(2,033,959)		
9	Total (lines 7 and 8)		(1,352,242)	315,861,850	314,509,608
10	Balance of Account 219 at End of Current Quarter/Year		(14,944,476)		

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)
1	UTILITY PLANT					
2	In Service					
3	Plant in Service (Classified)	8,256,626,938	8,256,626,938			
4	Property Under Capital Leases	219,612,133	219,612,133			
5	Plant Purchased or Sold					
6	Completed Construction not Classified					
7	Experimental Plant Unclassified					
8	Total (3 thru 7)	8,476,239,071	8,476,239,071			
9	Leased to Others					
10	Held for Future Use	19,781,026	19,781,026			
11	Construction Work in Progress	1,743,553,102	1,743,553,102			
12	Acquisition Adjustments	750,894	750,894			
13	Total Utility Plant (8 thru 12)	10,240,324,093	10,240,324,093			
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	2,763,239,071	2,763,239,071			
15	Net Utility Plant (13 less 14)	7,477,085,022	7,477,085,022			
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION					
17	In Service:					
18	Depreciation	2,704,938,418	2,704,938,418			
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	58,147,971	58,147,971			
22	Total in Service (18 thru 21)	2,763,086,389	2,763,086,389			
23	Leased to Others					
24	Depreciation					
25	Amortization and Depletion					
26	Total Leased to Others (24 & 25)					

27	Held for Future Use					
28	Depreciation					
29	Amortization					
30	Total Held for Future Use (28 & 29)					
31	Abandonment of Leases (Natural Gas)					
32	Amortization of Plant Acquisition Adjustment	152,682	152,682			
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,763,239,071	2,763,239,071			

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)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT		
2	In Service		
3	Plant in Service (Classified)		
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)		
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress		
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)		
14	Accumulated Provisions for Depreciation, Amortization, & Depletion		
15	Net Utility Plant (13 less 14)		
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION		
17	In Service:		
18	Depreciation		
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)		
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amortization of Plant Acquisition Adjustment		
33	Total Accum Prov (equals 14) (22,26,30,31,32)		

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication					
3	Nuclear Materials					
4	Allowance for Funds Used during Construction					
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)					
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL (Total 8 & 9)					
11	Spent Nuclear Fuel (120.4)					
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)					
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)					
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)
1	1. INTANGIBLE PLANT					
2	(301) Organization	5,703				
3	(302) Franchise and Consents	61,977,131	2,400,225			
4	(303) Miscellaneous Intangible Plant	86,841,416				(83,283,579)
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	148,824,250	2,400,225			(83,283,579)
6	2. PRODUCTION PLANT					
7	A. Steam Production Plant					
8	(310) Land and Land Rights	1,615,811		430,344		
9	(311) Structures and Improvements	123,778,697	25,911,469	47,714,985		
10	(312) Boiler Plant Equipment	656,101,334	8,699,998	144,990,457		
11	(313) Engines and Engine-Driven Generators	0				
12	(314) Turbogenerator Units	144,065,499	10,821,400	38,587,534		
13	(315) Accessory Electric Equipment	55,635,413	93,291	22,081,811		
13.1	(315.1) Computer Hardware					
13.2	(315.2) Computer Software					
13.3	(315.3) Communication Equipment					
14	(316) Misc. Power Plant Equipment	21,673,955	1,270,583	5,948,113		
15	(317) Asset Retirement Costs for Steam Production	39,743,122	(24,952,598)			

16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,042,613,831	21,844,143	259,753,244		
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	31,698,701	351,733			
28	(331) Structures and Improvements	303,622,156	17,539,088	379,843		
29	(332) Reservoirs, Dams, and Waterways	313,261,501	9,918,499	80,904		
30	(333) Water Wheels, Turbines, and Generators	396,819,306	17,797,424	1,594,351		
31	(334) Accessory Electric Equipment	83,115,745	4,303,549	413,478		
31.1	(334.1) Computer Hardware		322,407	25,855		508,277
31.2	(334.2) Computer Software		829,519			3,232,254
31.3	(334.3) Communication Equipment		295,900			547,556
32	(335) Misc. Power Plant Equipment	34,453,986	1,782,502	611,124		(1,055,833)
33	(336) Roads, Railroads, and Bridges	19,874,384	92,112	9,913		
34	(337) Asset Retirement Costs for Hydraulic Production					
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	1,182,845,779	53,232,733	3,115,468		3,232,254
35.1	D. Solar Production Plant					
35.2	(338.1) Land and Land Rights					9,788
35.3	(338.2) Structures and Improvements					2,976
35.5	(338.4) Solar Panels					79,331
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					12,592
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)					104,687
35.16	E. Wind Production Plant					
35.17	(338.20) Land and Land Rights					
35.18	(338.21) Structures and Improvements					
35.20	(338.23) Wind Turbines					
35.21	(338.24) Wind Towers and Fixtures					
35.23	(338.26) Collector System					
35.24	(338.27) Generator Step-up Transformers (GSU)					
35.25	(338.28) Inverters					
35.26	(338.29) Other Accessory Electrical Equipment					
35.27	(338.30) Computer Hardware					
35.28	(338.31) Computer Software					
35.29	(338.32) Communication Equipment					
35.30	(338.33) Miscellaneous Power Plant Equipment					
35.31	(338.34) Asset Retirement Costs for Wind Production					
35.32	TOTAL Wind Production Plant (Enter Total of lines 35.17 thru 35.31)					
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	2,699,794				(9,788)
38	(341) Structures and Improvements	158,019,434	1,226,477	798,152		(2,976)
39	(342) Fuel Holders, Products, and Accessories	10,978,278	734,000	151,813		
40	(343) Prime Movers	285,722,684	7,037,786	11,747,823		
41	(344) Generators	72,567,792	5,215,473	1,535,883		(79,331)
42	(345) Accessory Electric Equipment	95,066,742	471,299	186,575		
42.1	(345.1) Computer Hardware		2,329			209,997
42.2	(345.2) Computer Software					264,896
42.3	(345.3) Communication Equipment					147,710
43	(346) Misc. Power Plant Equipment	8,163,772	1,070,572	50,304		(370,299)
44	(347) Asset Retirement Costs for Other Production	0				
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	633,218,496	15,757,936	14,470,550		160,209
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, 35.15, 35.32, 35.47, and 45)	2,858,678,106	90,834,812	277,339,262		3,497,150
47	3. Transmission Plant					
48	(350) Land and Land Rights	43,932,977	1,453,778			
48.2	(351.1) Computer Hardware		(296,474)			6,991,909
48.3	(351.2) Computer Software		203,906	23,205		289,901
48.4	(351.3) Communication Equipment		748,137			16,130,362
49	(352) Structures and Improvements	129,252,140	22,643,655	566,108		
50	(353) Station Equipment	523,782,601	39,189,377	5,876,629		(23,122,271)
51	(354) Towers and Fixtures	260,481,419	13,344,233			
52	(355) Poles and Fixtures	266,220,072	15,757,380	404,594		
53	(356) Overhead Conductors and Devices	310,399,915	32,967,029	414,784		
54	(357) Underground Conduit	0				

55	(358) Underground Conductors and Devices	0				
56	(359) Roads and Trails	405,091				
57	(359.1) Asset Retirement Costs for Transmission Plant					
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,534,474,215	126,011,021	7,285,320		289,901
59	4. Distribution Plant					
60	(360) Land and Land Rights	10,722,128	712,842			
61	(361) Structures and Improvements	69,570,531	2,823,675	47,521		
62	(362) Station Equipment	369,699,424	48,833,948	1,026,356		(12,861,341)
63.1	(363.1) Computer Hardware		107,599			983,651
63.2	(363.2) Computer Software		1,114,152			6,508,661
63.3	(363.3) Communication Equipment		887,089			11,877,690
64	(364) Poles, Towers, and Fixtures	369,241,077	42,883,268	3,873,138		
65	(365) Overhead Conductors and Devices	175,052,853	12,304,671	1,455,027		
66	(366) Underground Conduit	60,294,278	3,791,816	278,446		
67	(367) Underground Conductors and Devices	366,282,560	20,921,549	2,345,802		
68	(368) Line Transformers	830,648,529	63,679,161	9,085,813		
69	(369) Services	74,656,442	3,653,443	538,077		
70	(370) Meters	126,714,280	9,555,627	4,446,198		
71	(371) Installations on Customer Premises	5,591,708	76,867	1,033,898		
72	(372) Leased Property on Customer Premises					
73	(373) Street Lighting and Signal Systems	6,948,734	183,587	480,732		
74	(374) Asset Retirement Costs for Distribution Plant					
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,465,422,544	211,529,294	24,611,008		6,508,661
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT					
77	(380) Land and Land Rights	0				
78	(381) Structures and Improvements	0				
79	(382) Computer Hardware	0				
80	(383) Computer Software	0				
81	(384) Communication Equipment	0				
82	(385) Miscellaneous Regional Transmission and Market Operation Plant	0				
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper	0				

84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)	0				
84.1	6. ENERGY STORAGE PLANT					
84.2	(387.1) Land and Land Rights	207,869	219,804			
84.3	(387.2) Structures and Improvements	32,652,992	15,788,688			
84.4	(387.3) Energy Storage Equipment	308,660,276	78,258,006			
84.6	(387.5) Collector System	33,121,672	3,598,557			
84.7	(387.6) Generator Step-up Transformers (GSU)	8,341,506	5,724,072			
84.8	(387.7) Inverters	10,028,006	5,848,022			
84.9	(387.8) Computer Hardware		2,981,104			
84.10	(387.9) Computer Software		2,274,607			
84.11	(387.10) Communication Equipment		615,398			
84.12	(387.11) Miscellaneous Energy Storage Equipment		1,419,469			
84.13	(387.12) Asset Retirement Costs for Energy Storage					
84.14	TOTAL Energy Storage Plant (Total lines 84.2 thru 84.13)	393,012,321	116,727,727			
85	7. General Plant					
86	(389) Land and Land Rights	21,077,174	149,483			
87	(390) Structures and Improvements	185,713,201	15,831,278	407,951		
88	(391) Office Furniture and Equipment	43,391,136	1,666,555	729,475		(30,290,653)
89	(392) Transportation Equipment	140,085,133	31,730,139	11,824,239		
90	(393) Stores Equipment	9,407,024	1,345,137	31,339		
91	(394) Tools, Shop and Garage Equipment	16,497,330	1,002,474	389,635		
92	(395) Laboratory Equipment	16,572,357	491,719	394,987		
93	(396) Power Operated Equipment	32,706,868	2,645,955	1,307,889		
94	(397.1) Computer Hardware		3,311,366	4,970,842		30,290,653
94.1	(397.2) Computer Software		19,283,301	3,795,928		72,987,867
94.2	(397.3) Communication Equipment	84,545,967	5,380,260	3,792,066		
95	(398) Miscellaneous Equipment	10,907,917	2,531,964	681,374		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	560,904,107	85,369,631	28,325,725		72,987,867
97	(399) Other Tangible Property					
98	(399.1) Asset Retirement Costs for General Plant					
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	560,904,107	85,369,631	28,325,725		72,987,867
100	TOTAL (Accounts 101 and 106)	7,961,315,543	632,872,710	337,561,315		

101	(102) Electric Plant Purchased (See Instr. 8)					
102	(Less) (102) Electric Plant Sold (See Instr. 8)					
103	(103) Experimental Plant Unclassified					
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	7,961,315,543	632,872,710	337,561,315		

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 at End of Year (g)
1	1. INTANGIBLE PLANT	
2	(301) Organization	5,703
3	(302) Franchise and Consents	64,377,356
4	(303) Miscellaneous Intangible Plant	3,557,837
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	67,940,896
6	2. PRODUCTION PLANT	
7	A. Steam Production Plant	
8	(310) Land and Land Rights	1,185,467
9	(311) Structures and Improvements	101,975,181
10	(312) Boiler Plant Equipment	519,810,875
11	(313) Engines and Engine-Driven Generators	
12	(314) Turbogenerator Units	116,299,365
13	(315) Accessory Electric Equipment	33,646,893
13.1	(315.1) Computer Hardware	
13.2	(315.2) Computer Software	
13.3	(315.3) Communication Equipment	
14	(316) Misc. Power Plant Equipment	16,996,425
15	(317) Asset Retirement Costs for Steam Production	14,790,524
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	804,704,730
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	32,050,434
28	(331) Structures and Improvements	320,781,401
29	(332) Reservoirs, Dams, and Waterways	323,099,096
30	(333) Water Wheels, Turbines, and Generators	413,022,379
31	(334) Accessory Electric Equipment	87,005,816
31.1	(334.1) Computer Hardware	804,829
31.2	(334.2) Computer Software	4,061,773
31.3	(334.3) Communication Equipment	843,456
32	(335) Misc. Power Plant Equipment	34,569,531
33	(336) Roads, Railroads, and Bridges	19,956,583
34	(337) Asset Retirement Costs for Hydraulic Production	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	1,236,195,298
35.1	D. Solar Production Plant	
35.2	(338.1) Land and Land Rights	9,788
35.3	(338.2) Structures and Improvements	2,976
35.5	(338.4) Solar Panels	79,331
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	12,592
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)	104,687
35.16	E. Wind Production Plant	
35.17	(338.20) Land and Land Rights	
35.18	(338.21) Structures and Improvements	
35.20	(338.23) Wind Turbines	
35.21	(338.24) Wind Towers and Fixtures	
35.23	(338.26) Collector System	
35.24	(338.27) Generator Step-up Transformers (GSU)	

35.25	(338.28) Inverters	
35.26	(338.29) Other Accessory Electrical Equipment	
35.27	(338.30) Computer Hardware	
35.28	(338.31) Computer Software	
35.29	(338.32) Communication Equipment	
35.30	(338.33) Miscellaneous Power Plant Equipment	
35.31	(338.34) Asset Retirement Costs for Wind Production	
35.32	TOTAL Wind Production Plant (Enter Total of lines 35.17 thru 35.31)	
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	2,690,006
38	(341) Structures and Improvements	158,444,783
39	(342) Fuel Holders, Products, and Accessories	11,560,465
40	(343) Prime Movers	281,012,647
41	(344) Generators	76,168,051
42	(345) Accessory Electric Equipment	95,351,466
42.1	(345.1) Computer Hardware	212,326
42.2	(345.2) Computer Software	264,896
42.3	(345.3) Communication Equipment	147,710
43	(346) Misc. Power Plant Equipment	8,813,741
44	(347) Asset Retirement Costs for Other Production	0
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	634,666,091
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, 35.15, 35.32, 35.47, and 45)	2,675,670,806
47	3. Transmission Plant	
48	(350) Land and Land Rights	45,386,755
48.2	(351.1) Computer Hardware	6,695,435
48.3	(351.2) Computer Software	470,602
48.4	(351.3) Communication Equipment	16,878,499

49	(352) Structures and Improvements	151,329,687
50	(353) Station Equipment	533,973,078
51	(354) Towers and Fixtures	273,825,652
52	(355) Poles and Fixtures	281,572,858
53	(356) Overhead Conductors and Devices	342,952,160
54	(357) Underground Conduit	
55	(358) Underground Conductors and Devices	
56	(359) Roads and Trails	405,091
57	(359.1) Asset Retirement Costs for Transmission Plant	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,653,489,817
59	4. Distribution Plant	
60	(360) Land and Land Rights	11,434,970
61	(361) Structures and Improvements	72,346,685
62	(362) Station Equipment	404,645,675
63.1	(363.1) Computer Hardware	1,091,250
63.2	(363.2) Computer Software	7,622,813
63.3	(363.3) Communication Equipment	12,764,779
64	(364) Poles, Towers, and Fixtures	408,251,207
65	(365) Overhead Conductors and Devices	185,902,497
66	(366) Underground Conduit	63,807,648
67	(367) Underground Conductors and Devices	384,858,307
68	(368) Line Transformers	885,241,877
69	(369) Services	77,771,808
70	(370) Meters	131,823,709
71	(371) Installations on Customer Premises	4,634,677
72	(372) Leased Property on Customer Premises	
73	(373) Street Lighting and Signal Systems	6,651,589
74	(374) Asset Retirement Costs for Distribution Plant	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,658,849,491
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	427,673

84.3	(387.2) Structures and Improvements	48,441,680
84.4	(387.3) Energy Storage Equipment	386,918,282
84.6	(387.5) Collector System	36,720,229
84.7	(387.6) Generator Step-up Transformers (GSU)	14,065,578
84.8	(387.7) Inverters	15,876,028
84.9	(387.8) Computer Hardware	2,981,104
84.10	(387.9) Computer Software	2,274,607
84.11	(387.10) Communication Equipment	615,398
84.12	(387.11) Miscellaneous Energy Storage Equipment	1,419,469
84.13	(387.12) Asset Retirement Costs for Energy Storage	
84.14	TOTAL Energy Storage Plant (Total lines 84.2 thru 84.13)	509,740,048
85	7. General Plant	
86	(389) Land and Land Rights	21,226,657
87	(390) Structures and Improvements	201,136,528
88	(391) Office Furniture and Equipment	14,037,563
89	(392) Transportation Equipment	159,991,033
90	(393) Stores Equipment	10,720,822
91	(394) Tools, Shop and Garage Equipment	17,110,169
92	(395) Laboratory Equipment	16,669,089
93	(396) Power Operated Equipment	34,044,934
94	(397.1) Computer Hardware	28,631,177
94.1	(397.2) Computer Software	88,475,240
94.2	(397.3) Communication Equipment	86,134,161
95	(398) Miscellaneous Equipment	12,758,507
96	SUBTOTAL (Enter Total of lines 86 thru 95)	690,935,880
97	(399) Other Tangible Property	
98	(399.1) Asset Retirement Costs for General Plant	
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	690,935,880
100	TOTAL (Accounts 101 and 106)	8,256,626,938
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)	8,256,626,938

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: LandAndLandRightsEnergyStoragePlant

The Balance Beginning of Year (b) reported reflects the Company's Balance at End of Year for line 63 (363) Energy Storage Equipment – Distribution reported within the Company's 12/31/2024 FERC Form 1 page 204. Plant assets previously classified within account (363) Energy Storage Equipment – Distribution as of 12/31/2024 were transferred at the beginning of 2025 to the newly available 387 series accounts for Energy Storage Plant, with the implementation of FERC Rule No. 898.

(b) Concept: StructuresAndImprovementsEnergyStoragePlant

The Balance Beginning of Year (b) reported reflects the Company's Balance at End of Year for line 63 (363) Energy Storage Equipment – Distribution reported within the Company's 12/31/2024 FERC Form 1 page 204. Plant assets previously classified within account (363) Energy Storage Equipment – Distribution as of 12/31/2024 were transferred at the beginning of 2025 to the newly available 387 series accounts for Energy Storage Plant, with the implementation of FERC Rule No. 898.

(c) Concept: EnergyStorageEquipmentEnergyStoragePlant

The Balance Beginning of Year (b) reported reflects the Company's Balance at End of Year for line 63 (363) Energy Storage Equipment – Distribution reported within the Company's 12/31/2024 FERC Form 1 page 204. Plant assets previously classified within account (363) Energy Storage Equipment – Distribution as of 12/31/2024 were transferred at the beginning of 2025 to the newly available 387 series accounts for Energy Storage Plant, with the implementation of FERC Rule No. 898.

(d) Concept: CollectorSystemEnergyStoragePlant

The Balance Beginning of Year (b) reported reflects the Company's Balance at End of Year for line 63 (363) Energy Storage Equipment – Distribution reported within the Company's 12/31/2024 FERC Form 1 page 204. Plant assets previously classified within account (363) Energy Storage Equipment – Distribution as of 12/31/2024 were transferred at the beginning of 2025 to the newly available 387 series accounts for Energy Storage Plant, with the implementation of FERC Rule No. 898.

(e) Concept: GeneratorStepupTransformersEnergyStoragePlant

The Balance Beginning of Year (b) reported reflects the Company's Balance at End of Year for line 63 (363) Energy Storage Equipment – Distribution reported within the Company's 12/31/2024 FERC Form 1 page 204. Plant assets previously classified within account (363) Energy Storage Equipment – Distribution as of 12/31/2024 were transferred at the beginning of 2025 to the newly available 387 series accounts for Energy Storage Plant, with the implementation of FERC Rule No. 898.

(f) Concept: InvertersEnergyStoragePlant

The Balance Beginning of Year (b) reported reflects the Company's Balance at End of Year for line 63 (363) Energy Storage Equipment – Distribution reported within the Company's 12/31/2024 FERC Form 1 page 204. Plant assets previously classified within account (363) Energy Storage Equipment – Distribution as of 12/31/2024 were transferred at the beginning of 2025 to the newly available 387 series accounts for Energy Storage Plant, with the implementation of FERC Rule No. 898.

(g) Concept: EnergyStoragePlant

The Balance Beginning of Year (b) reported reflects the Company's Balance at End of Year for line 63 (363) Energy Storage Equipment – Distribution reported within the Company's 12/31/2024 FERC Form 1 page 204. Plant assets previously classified within account (363) Energy Storage Equipment – Distribution as of 12/31/2024 were transferred at the beginning of 2025 to the newly available 387 series accounts for Energy Storage Plant, with the implementation of FERC Rule No. 898.

(h) Concept: CommunicationEquipment

The Balance Beginning of Year (b) reported reflects the Company's Balance at End of Year for line 94 (397) Communication Equipment reported within the Company's 12/31/2024 FERC Form 1 page 204. Plant assets previously classified within account (397) Communication Equipment as of 12/31/2024 were transferred at the beginning of 2025 to the newly available account 397.3 Communication Equipment, with the implementation of FERC Rule No. 898.

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	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)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						

34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47	TOTAL						

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Production:			
3	Production			104,155
4	Bennett Mtn Plant Expansion	12/20/2024	06/30/2028	2,072,883
5	Peregrine Power Plan	11/22/2024	06/30/2027	235,616
6	Transmission:			
7	Transmission Lines			194,538
8	Transmission Stations			377,466
9	Line #733 203Kv	04/07/2025	12/31/2028	1,462,996
10	Line #734 203Kv	04/07/2025	12/31/2030	291,458
11	Line #736 203Kv	04/07/2025	12/31/2032	432,437
12	Line #853 500Kv	12/16/2011	12/31/2027	598,188
13	Line #854 500Kv	03/31/2009	12/31/2028	308,066
14	Mayfield Transmission Station	06/30/1981	12/31/2028	2,519,173
15	Midpoint Transmission Station	06/30/1992	09/30/2027	870,843
16	Palette Junction Substation	03/15/2021	12/31/2028	744,012
17	Distribution:			
18	Distribution Lines			25,581
19	Distribution Substations			1,168,572
20	Crossroads Substation	01/31/2024	06/30/2027	530,994
21	Eisenman Substation	07/14/2025	06/30/2030	1,610,866
22	Farmway Station	12/22/2022	06/30/2030	947,032
23	Gem Substation	05/15/2024	06/30/2026	525,507
24	Greenleaf Substation	08/02/2024	12/31/2027	417,665
25	Lake Hazel Substation	10/22/2024	06/30/2030	745,547
26	McDermott Substation	10/26/2022	12/31/2026	1,330,604
27	Northside Substation	02/01/2023	06/30/2030	1,315,214
28				
29				
30				
31				

32	Columns b and c if no date listed it is various			
33				
21	Other Property:			
22	Transmission Stations			199,069
23	Distribution Stations			54,561
24	Distribution Underground Vault, Blain County	08/30/2016	12/31/2026	443,545
25	Peregrine Power Plant	09/29/2025	06/30/2027	254,438
26	Columns b and c if no date listed it is various			
47	TOTAL			19,781,026

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)
1	Land and Rights:
2	Production:
3	Production
4	Bennett Mtn Plant Expansion
5	Peregrine Power Plan
6	Transmission:
7	Transmission Lines
8	Transmission Stations
9	Line #733 203Kv
10	Line #734 203Kv
11	Line #736 203Kv
12	Line #853 500Kv
13	Line #854 500Kv
14	Mayfield Transmission Station
15	Midpoint Transmission Station
16	Palette Junction Substation
17	Distribution:
18	Distribution Lines
19	Distribution Substations
20	Crossroads Substation
21	Eisenman Substation
22	Farmway Station
23	Gem Substation
24	Greenleaf Substation
25	Lake Hazel Substation
26	McDermott Substation
27	Northside Substation
28	
29	
30	
31	
32	Columns b and c if no date listed it is various
33	

21	Other Property:
22	Transmission Stations
23	Distribution Stations
24	Distribution Underground Vault, Blain County
25	Peregrine Power Plant
26	Columns b and c if no date listed it is various
47	TOTAL

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

CONSTRUCTION WORK IN PROGRESS -- ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107)
		(b)
1	HGSN220001 - HGSN T052 NEW XFM	1,000,576
2	EKRT41 - WMP HARDENING - F534	1,020,087
3	PRFS230001-BUILD NEW CKT, GETA	1,021,840
4	OXBOW TURBINE AND GENERATOR RE	1,023,601
5	AM FALLS RELIC: PRE-APPLICATI	1,027,729
6	OBSY240001 - OXBOW SWITCHYARD	1,043,123
7	BSPO BOP MODERNIZATION	1,061,884
8	T209180001 DRKE TO BCSR 69KV R	1,063,977
9	DEMAND SIDE MANAGEMENT	1,065,808
10	COMMON ASSET: NEW 345KV SERIES	1,084,011
11	T852- SWIP - SOUTHWEST INTERTI	1,099,470
12	HCPR220011 - POWER PLANT/DAM P	1,104,467
13	UTILITY NETWORK APPLICATION MI	1,106,547
14	AFPR UNIT 2 TURBINE REFURB	1,109,155
15	HMWY250001 LINE TERMINAL FOR G	1,110,660
16	OXBOW POWER PLANT ERECTION DEC	1,114,201
17	GOODING WAREHOUSE EXPANSION	1,116,521
18	ENTERPRISE DATA STRATEGY - GIS	1,129,909
19	2025 SRMMP FUNDING	1,131,954
20	2025 SRMMP FUNDING 50%	1,131,954
21	RELC - ITD US 20-26, MIDDLETON	1,145,766
22	EDEN - ADD NEW T133 TRANSFORME	1,164,920
23	VALMY 3128 V2 DISTRIBUTED CONT	1,181,296
24	VALMY V1 BUY BACK INTO CAPITAL	1,190,197
25	RRFH BRIDGE CONSTRUCTION	1,200,853
26	VEGETATION MANAGEMENT LEGACY S	1,203,945
27	ADEL250001-REPLACE (2) 345:13	1,214,898
28	GNLF180001- NEW SUBSTATION NEA	1,231,548
29	T482 MORA-BOMT 138-KV, REBUILD	1,233,674
30	NEW0901 138KV WDRI-KCHM OVERHE	1,272,321
31	HBRD NEW T731 230KV TERMINAL F	1,301,257
32	V1 VALMY 10527575 DISTRIBUTED	1,328,427

33	HSDL INSTALL 44.8MVA TRANSFORM	1,333,287
34	KRMR160001- REPLACE UFR	1,389,908
35	ENTERPRISE DATA STRATEGY - OMS	1,392,054
36	IDOT2402 - SH-55, FARMWAY TO M	1,392,774
37	CITY OF KETCHUM - SH-75 OH TO	1,407,180
38	KUNA230001-INSTALL NEW KUNA 01	1,469,279
39	GEMM230002 UPGRADE GEMM T-061	1,521,014
40	LTP - ROTOR REPLACEMENT (STAND	1,571,512
41	RMVW SUBSTATION	1,583,123
42	HCC MERCURY NUMERIC MODEL DEVE	1,616,218
43	WHOLLY OWNED - ANTS UPGRADES F	1,632,047
44	HELLS CANYON NOAA BIOLOGICAL A	1,647,827
45	BOBN200004 - FEEDER RELAY AND	1,673,526
46	COMMON ASSET: RPL 138 & 230KV	1,757,189
47	PRFS230001 - REBUILD LINE 452	1,764,074
48	MCDT220001 BUILD NEW MCDERMOTT	1,806,885
49	HBRD250001 - PERIMETER SECURIT	1,823,264
50	FALL CHINOOK PROGRAM - ENTRAPM	1,939,574
51	BROWNLEE SPILLWAY REHABILITATI	2,051,809
52	RAPID RIVER HATCHERY RENOVATIO	2,143,956
53	STAR240001- NEW FEEDER 017	2,153,950
54	T445230001 - NEW 138KV LINE (K	2,232,792
55	NEWX230002 MIDLINE STATION FOR	2,308,241
56	NTSD230002 ADD 3 DIST. FEEDERS	2,410,183
57	CADA220001-NEW CADA 015, 016,	2,528,365
58	NTSD ADD SECOND METALCLAD	2,689,736
59	IPC ONLY: RPL 138 & 230KV PCBS	2,705,748
60	T7261001 HMWY-BOMT 230KV 2ND C	2,723,361
61	AFPR UNIT 3 TURBINE REFURB	2,830,625
62	CTG - GENERATOR REWIND	3,309,509
63	LINE 902 REBUILD - STR 685-88	3,318,125
64	DISTRIBUTION WORK FOR 2ND WDRI	3,355,642
65	OXBOW UNIT 4 TURBINE AND GENER	3,416,603
66	COMMON ASSET - HMWY230002 - AD	3,457,973
67	CADA INSTALL NEW 44.8MVA CADAT	3,568,759
68	MYFD240001 NEW MAYFIELD STATIO	3,585,821
69	BSPO TURBINE & GENERATOR REFUR	3,625,956
70	NEWX230003 LONGHORN STATION FO	3,634,744
71	T163180001 REBUILD 46KV LINE T	3,757,101
72	VARI260005 - BOBN PROCURE SPAR	3,760,918

73	HOT GAS PATH FX UPGRADE	3,774,074
74	COMMON ASSET: PH 3, MPSN INSTA	3,834,464
75	AMITY DATA CENTER (AMDC) FACIL	3,844,227
76	T219220003 - REBUILD LINE FROM	4,004,900
77	DISTRIBUTION WORK FOR 2ND WDRI	4,171,132
78	AFPR UNIT 2 REWIND	4,213,040
79	REPORTING MODEL FOR SNAKE RIVE	4,856,889
80	OXBOW UNIT 3 TURBINE AND GENER	5,290,127
81	T244240001 - T919 REBUILD - SL	5,561,112
82	FALL CHINOOK PROGRAM - REDD SU	5,788,976
83	T410 REBUILD LPJN-MNJ1 LINE SE	6,460,661
84	SWML240001 - NEW 138KV SAWMILL	6,470,276
85	JOINT ASSET: PH 3, INSTALL MPS	6,684,375
86	OBPR220015 - POWER PLANT/DAM P	6,873,165
87	PRFS230001 NEW 138:12.5KV SUBS	6,960,367
88	HC SEDIMENT PROGRAMS	6,969,367
89	DISTRIBUTION WORK FOR 2ND WDRI	7,000,266
90	DISTRIBUTION WORK FOR 2ND WDRI	7,619,529
91	REL-HCC OREGON REAUTHORIZATION	8,401,011
92	REPLACE THE STEAM TURBINE GENE	9,375,037
93	B2H TLINE PRE-CONSTRUCTION COS	9,939,908
94	BULL TROUT PROGRAM - ADMINISTR	9,997,087
95	LEGAL DEPT. LABOR FOR RELICENS	10,086,931
96	T908200001 - T908 PLET TO INHA	10,840,857
97	BSPO TURBINE & GENERATOR REFUR	10,866,400
98	OBPR UNIT 2 TURBINE AND GENERA	11,116,316
99	VALMY 10507167 V2 VALMY GAS CO	11,594,973
100	STEAM TURBINE MAJOR INSPECTION	11,781,573
101	OXBOW UNIT 1 TURBINE AND GENER	12,217,786
102	CIS TRANSFORMATION	12,674,439
103	GRID MOD SINGLE VENDOR PLATFOR	13,371,596
104	HCC WATERSHED ENHANCEMENT PROG	13,595,163
105	T731 RECONSTRUCT THE BOMT-HBRD	14,174,961
106	BOARDMAN - HEMINGWAY 500 KV LI	15,622,357
107	T533230001- 138KV WDRI-KCHM UG	16,357,142
108	GATEWAY WEST 500KV LINE PRE-CO	16,625,612
109	B2H - SAGR MITIGATION BANK	17,088,072
110	WQ HCC401 CERTIFICATION OPS AN	17,387,926
111	T731 RECONSTRUCT THE BOMT-HBRD	19,106,375
112	OXBOW SPILLWAY REHABILITATION	24,637,047

113	SCCT FACILITY CONSTRUCTION	24,827,520
114	RICE FACILITY CONSTRUCTION	30,976,775
115	IPC FUNDING - BPA PERMITTING/P	41,128,859
116	B2H PERMITTING 11/1/2011 & FOR	48,820,027
117	B2H: RIGHTS OF WAY	51,126,662
118	HELLS CANYON RELICENSING OUTSI	57,062,224
119	HMWY BESS - 50MW EXPANSION 202	57,468,336
120	B2H: LIMITED CONSTRUCTION FUND	60,630,303
121	ROLLUP RELIC COST OXBOW	65,046,669
122	GATEWAY WEST 500KV LINE	67,114,793
123	B2H TLINE CONSTRUCTION COSTS	71,478,042
124	ROLLUP RELIC COST HELLS CANYON	139,390,332
125	ROLLUP RELIC COST BROWNLEE	204,956,700
126	BOBS BESS DEVELOPMENT - 2026 R	208,956,004
127	Other Minor Projects Under \$1,000,000	86,807,112
43	Total	1,743,553,102

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

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

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

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
Section A. Balances and Changes During Year					
1	Balance Beginning of Year	2,830,763,125	2,830,763,125	0	0
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	235,309,143	235,309,143		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	8,067,984	8,067,984		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Fuel stock	40,359	40,359		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	243,417,486	243,417,486		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(333,742,182)	(333,742,182)		
13	Cost of Removal	(27,175,434)	(27,175,434)		
14	Salvage (Credit)	6,687,151	6,687,151		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(354,230,465)	(354,230,465)		
16	Other Debit or Cr. Items (Describe, details in footnote):	(15,011,728)	(15,011,728)		
17.1					
17.2					
17.3					
17.4					
17.5					
18	Book Cost or Asset Retirement Costs Retired	0	0		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,704,938,418	2,704,938,418		

Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	569,380,444	569,380,444		
21	Nuclear Production				
22	Hydraulic Production-Conventional	566,558,519	566,558,519		
23	Hydraulic Production-Pumped Storage				
23.1	Solar Production	33,764	33,764		
23.2	Wind Production				
23.3	Other Renewable Production				
24	Other Production	150,801,327	150,801,327		
25	Transmission	469,897,498	469,897,498		
26	Distribution	756,211,310	756,211,310		
27	Regional Transmission and Market Operation				
27.1	Energy Storage	34,468,376	34,468,376		
28	General	157,587,180	157,587,180		
29	TOTAL (Enter Total of lines 20 thru 28)	2,704,938,418	2,704,938,418		

(a) Concept: OtherAdjustmentsToAccumulatedDepreciation

Includes:

Valmy depreciation adjustments (ID Order No. 33771 and OR Order No. 17-235)

Bridger depreciation adjustments (ID Order No. 35423)

CIAC and Asset Retirement Obligation activity

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	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)
1	Common Stock			500		
2	Capital Contributions			2,462,593		
3	Equity in Earnings			21,913,594	2,248,634	
4						
42	Total Cost of Account 123.1 \$		Total	24,376,687	2,248,634	

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)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1	Common Stock	500	
2	Capital Contributions	2,462,593	
3	Equity in Earnings	24,162,228	
4			
42	Total Cost of Account 123.1 \$	26,625,321	

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	43,656,474	24,454,598	
2	Fuel Stock Expenses Undistributed (Account 152)	0		
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	15,140,393	20,919,071	
8	Transmission Plant (Estimated)	73,154,194	47,600,579	
9	Distribution Plant (Estimated)	90,397,818	64,365,922	
10	Regional Transmission and Market Operation Plant (Estimated)			
10.1	Energy Storage Plant (Estimated)		50,337,305	
11	Assigned to - Other (provide details in footnote)	①1,950,445	②2,210,586	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	180,642,850	185,433,463	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	0		
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	20,421,571	16,463,017	
17				
18				
19				
20	TOTAL Materials and Supplies	244,720,895	226,351,078	

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesOther

This amount represents miscellaneous inventory that is not yet assigned to a particular function.

(b) Concept: PlantMaterialsAndOperatingSuppliesOther

This amount represents miscellaneous inventory that is not yet assigned to a particular function.

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

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

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

Line No.	Allowances and Environmental Credits Inventory (Accounts 158.1, 158.3, and 158.4) (a)	Current Year		Year One		Year Two	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)
1	Balance-Beginning of Year						
2							
3	Acquired During Year:						
4	Issued (Less Withheld Allow)			33,000	988,460		
5	Returned by authoritative agency						
6							
7							
8	^(a) Transfers	15,653	553,675				
9							
10							
11							
12							
13							
14							
15	Total						
16							
17	Relinquished During Year:						
18	Charges to Account 509, 555.2, and 555.3	4,815	182,247				
19	Other:						
20	Allowances Used						
20.1							
21	Cost of Sales/Transfers:						

22							
23							
24							
25							
26							
27							
28	Total						
29	Balance-End of Year	10,838	371,428	33,000	988,460		
30							
31	Sales:						
32	Net Sales Proceeds(Assoc. Co.)						
33	Net Sales Proceeds (Other)						
34	Gains						
35	Losses						
	Allowances Withheld (Acct 158.2)						
36	Balance-Beginning of Year						
37	Add: Withheld by authoritative agency						
38	Deduct: Returned by authoritative agency						
39	Cost of Sales						
40	Balance-End of Year						
41							
42	Sales						
43	Net Sales Proceeds (Assoc. Co.)						
44	Net Sales Proceeds (Other)						
45	Gains						
46	Losses						

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

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

Line No.	Allowances and Environmental Credits Inventory (Accounts 158.1, 158.3, and 158.4) (a)	Year Three		Future Years		Totals	
		No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year						
2							
3	Acquired During Year:						
4	Issued (Less Withheld Allow)					33,000	988,460
5	Returned by authoritative agency					0	0
6							
7							
8	^(a) Transfers					15,653	553,675
9							
10							
11							
12							
13							
14							
15	Total					15,653	553,675
16							
17	Relinquished During Year:						
18	Charges to Account 509, 555.2, and 555.3					4,815	182,247
19	Other:						
20	Allowances Used					0	0
20.1						0	0
21	Cost of Sales/Transfers:						
22						0	0
23							

24							
25							
26							
27							
28	Total					0	0
29	Balance-End of Year					43,838	1,359,888
30							
31	Sales:						
32	Net Sales Proceeds(Assoc. Co.)					0	0
33	Net Sales Proceeds (Other)					0	0
34	Gains					0	0
35	Losses					0	0
	Allowances Withheld (Acct 158.2)						
36	Balance-Beginning of Year						
37	Add: Withheld by authoritative agency					0	0
38	Deduct: Returned by authoritative agency					0	0
39	Cost of Sales					0	0
40	Balance-End of Year					0	0
41							
42	Sales						
43	Net Sales Proceeds (Assoc. Co.)					0	0
44	Net Sales Proceeds (Other)					0	0
45	Gains					0	0
46	Losses					0	0

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: AllowancesInventoryPurchasesTransfersDescription
Allowances transferred from FERC account 186.

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: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

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

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
2	PWX LTF PTP TSR 102556728	0	186623	30,544	186623
3	PWX LTF PTP TSR 102556729	0	186623	30,637	186623
4	PWX LTF PTP TSR 102556730	0	186623	31,374	186623
5	ENKP LTF PTP TSR 103945029	845	186623	7,274	186623
6	ENKP LTF PTP TSR 103945038	2,367	186623	5,752	186623
7	MSCG LTF PTP TSR 106013913	7,281	186623	(7,281)	186623
8	MSCG LTF PTP TSR 106013914	6,358	186623	(6,358)	186623
9	IPCL LTF NETWORK TSR 105303223	3,314	186623	(3,314)	186623
10	PWX LTF PTP TSR 105883864	1,527	186623	(1,527)	186623
11	PWX LTF PTP TSR 105883865	1,166	186623	(1,166)	186623
12	PWX LTF PTP TSR 105883866	1,166	186623	(1,166)	186623
13	P66T LTF PTP TSR 1079298554	1,545	186623	(1,331)	186623
14	P66T LTF PTP TSR 1079298555	1,545	186623	(1,331)	186623
15	BPA CF REASSESSMENT 91629500 AND 91629850	1,061	186623	0	186623
16	PAC CF REASSESSMENT 93142712	531	186623	0	186623
17	ENKP LTF PTP TSR 106091167	857	186623	(857)	186623
18	ENKP LTF PTP TSR 1063091518	857	186623	(857)	186623
19	P66T LTF PTP TSR 107589576	0	186623	(10,000)	186623
20	P66T LTF PTP TSR 107589579	0	186623	(10,000)	186623
20	Total	30,420		60,393	
21	Generation Studies				
22	MOSBY BUTTE SOLAR #623	0	186623	8,719	186623
23	GEM VALE 1 #624	2,614	186623	19,081	186623
24	GEM VALE 2 #625	411	186623	19,409	186623
25	HMWY ENERGY STORAGE 2 #629	1,472	186623	0	186623
26	WILSON #632	0	186623	(270)	186623
27	TAURUS WIND #635	40,237	186623	(45,989)	186623

28	SOLES REST #636	5,680	186623	0	186623
29	BOBN ENERGY STORAGE 1 #639	492	186623	0	186623
30	KUNA STORAGE GI PROJECT #657	(4,694)	186623	0	186623
31	OLNEY GI PROJECT #662	(116)	186623	0	186623
32	BLACKS CREEK EC GI PROJECT #665	3,780	186623	(10,000)	186623
33	MARTHA FIELDS EC I GI PROJECT #667	13,230	186623	(31,404)	186623
34	KCE ID 1 GI PROJECT #696	(811)	186623	39	186623
35	APPALOOSA WIND & SOLAR LOS/OIS STUDIES #590	856	186623	41,471	186623
36	BENNETT 1 SOLAR GI PROJECT #551 ESS STUDY	0	186623	18,836	186623
37	PINGREE SOLAR RESTUDY GI PROJECT #654	0	186623	14,618	186623
38	GATHER ADDITIONAL STUDIES #633	0	186623	18,141	186623
39	CRIMSON ORCHARD SOLAR GI PROJECT #604	0	186623	9,626	186623
40	CLUSTER AREA 1 - EAST OF PATH 17 TRANSITIONAL CLUSTER STUDY	13,301	186623	(43,930)	186623
41	CLUSTER AREA 6 - B2H	8,515	186623	(21,600)	186623
42	CLUSTER AREA 3 - BOISE EAST TO MIDPOINT WEST TRANSITIONAL CL	11,178	186623	(23,613)	186623
43	CLUSTER AREA 4 - GREATER TREASUREVALLEY AREA TRANSITIONAL CL	38,302	186623	(66,621)	186623
44	CLUSTER AREA 5 - EAST OF PATH 14 TRANSITIONAL CLUSTER	12,379	186623	(23,735)	186623
45	BLACK CANYON IRRIGATION GI PROJECT #746	0	186623	15,906	186623
46	HUNT BESS 1 #748	6,340	186623	(7,730)	186623
47	HUNT BESS 2 #749	4,399	186623	(5,579)	186623
48	HUNT BESS 3 #750	4,491	186623	(5,608)	186623
49	CANYON CREEK BESS 1 #751	2,407	186623	(5,080)	186623
50	PILLAR POWER PRODUCTION 2, LLC GI PROJECT #747	4,604	186623	27,113	186623
51	FRY FOODS GI PROJECT #752	7,953	186623	(13,348)	186623
52	PLEASANT VALLEY SOLAR (2) GI #588	489	186623	8,050	186623
53	OLNEY GENERATING FACILITY GI PROJECT #662	22,317	186623	0	186623
54	APPALOOSA WIND AND SOLAR 1 #590	12,534	186623	(30,000)	186623
55	EMMETT MAIN CANAL GI PROJECT #755	6,625	186623	(12,600)	186623
56	ORCHARD LDES #756	11,165	186623	0	186623
57	JACKALOPE 1 GI PROJECT #607	19,410	186623	(40,000)	186623
58	JACKALOPE 2 GI PROJECT #608	10,950	186623	(40,000)	186623
59	MAGIC VALLEY ENERGY, LLC GI PROJECT #570	17,176	186623	(17,176)	186623
60	MAGIC VALLEY ENERGY 2 GI PROJECT #587	17,634	186623	(17,634)	186623

61	CLUSTER 1 - CLUSTER AREA 1 - CLUSTER STUDY	70,445	186623	(525,942)	186623
62	CLUSTER 1 - CLUSTER AREA 2 - CLUSTER STUDY	31,354	186623	(260,145)	186623
63	CLUSTER 1 - CLUSTER AREA 3 - CLUSTER STUDY	12,434	186623	(12,312)	186623
64	CLUSTER 1 - CLUSTER AREA 4 - CLUSTER STUDY	64,779	186623	(2,261,887)	186623
65	CLUSTER 1 - CLUSTER AREA 6 - CLUSTER STUDY	160,355	186623	(400,000)	186623
66	SOUTH BENNETT SOLAR #605	8,735	186623	(30,000)	186623
67	BENNETT 1 SOLAR #551	10,311	186623	(30,000)	186623
68	FALCON GENERATING FACILITY #659	8,875	186623	(30,000)	186623
69	SCHEDULE 68 DER PROJECT #20204	1,124	186623	(1,000)	186623
70	JACKALOPE 3 GI PROJECT #609	0	186623	0	186623
71	MILNER HYDRO UNITS 1 & 2 #753	708	186623	0	186623
72	AMERICAN FALLS POWER PLANT #795	591	186623	0	186623
73	PEREGRINE 1 #759	195	186623	0	186623
74	PEREGRINE 2 #760	195	186623	0	186623
75	MAYFIELD #796	1,342	186623	0	186623
76	MILNER #797	1,580	186623	0	186623
77	CLUSTER 1 - CLUSTER MONA - CLUSTER STUDY	1,813	186623	(250,000)	186623
78	GATHER RESTUDIES #633	187	186623	(30,000)	186623
79	ONTARIO SOLAR #525	308	186623	(5,000)	186623
80	MORGAN SOLAR #510	308	186623	(5,000)	186623
81	VALE 1 SOLAR #511	308	186623	(5,000)	186623
82	LUCKY PEAK #237	197	186623	(10,000)	186623
83	LANGLEY GULCH #239/313/610/695	489	186623	0	186623
84	LUNAR LANDING #783	0	186623	(10,000)	186623
85	ARH SOLAR #558	0	186623	(10,000)	186623
39	Total	671,953		(4,137,194)	
40	Grand Total	702,373		(4,076,801)	

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

[\(a\)](#) Concept: StudyCostsReimbursements

Amounts in this column represent both deposits received (credit amounts) and refunds of deposits that exceeded actual costs (debit amounts).

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Fixed Cost Adjustment (FCA) (182302)	(3,060,213)	5,052,733	1823	0	1,992,520
2	IPUC Order Pending (Amort period 06/26 thru 05/27)					
3	2026 RFP Deferral - IE (182317)	385,311	19,352	401	404,663	0
4	OPUC Advice UM2272					
5	WMP Deferral - OR (182311)	749,225	2,016,331		0	2,765,556
6	OPUC Order #24-010					
7	AOCI Impact of Unfunded Pension Liability	(24,716,580)	24,716,580	2283	0	0
8	IPUC Order #30256 (182320)					
9	FCA Calendar Mo Adjustment (182308)	4,334,505	1,878,191	400	0	6,212,696
10	Prior Year FCA (182309)	16,486,813	74,442	400	17,911,679	(1,350,424)
11	IPUC Order #36194 (Amort period 06/24 thru 05/25); IPUC Order #36617 (Amort period 06/25 thru 05/26)					
12	ID Intervenor Funding Amort (182388)	230,037	53,887	400	38,340	245,584
13	IPUC Order #36042 (Amort period 01/24 thru 12/30)					
14	AOCI Impact of Unfunded Pension Liability	43,540,260	0	254	43,540,260	0
15	IPUC Order #30256 (182320)					
16	Deferred Pension Expense Net of Contributions	2,787,543	18,158,037	1823	19,114,000	1,831,580
17	IPUC Order #30333 (182321)					
18	FAS 109 Unfunded (182322)	625,350,497	51,751,735	Various	26,728,848	650,373,384
19	Accum Deferred Income Noncurrent					
20	Idaho Pension Cash - IPUC Order #32248 (182327)	249,409,187	31,281,210	Various	35,182,378	245,508,019
21	Amort period 06/11 thru indefinite					
22	Mark- to Market Short Term (182330)	16,310,043	16,650,449			32,960,492

23	Oregon Pension Expense Capitalized (182339)	7,230,554	349,216	4073	255,738	7,324,032
24	OPUC Order #10-064					
25	Asset Retirement Obligations (182341)	37,841,697	24,323,966		0	62,165,663
26	IPUC Order #29414; OPUC Order #04-585					
27	RA-Hells Canyon-Baker Co (182360)	313,506	0		0	313,506
28	IPUC Order #33948					
29	Oregon Corporate Activity Tax (182355)	376,669	9,376	Various	386,045	0
30	OPUC Order #20-397					
31	Oregon Community Solar (182378)	215,902	152,283	Various	235,677	132,508
32	OPUC Order #16-410					
33	Intervenor Funding-Idaho (182387)	51,058	28,899		0	79,957
34	Multiple IPUC Orders					
35	RA-CONTRA-DEF INC TAX (182389)	185,703,192	0	282	14,731,055	170,972,137
36	Langley Revenue Accrual (182398)	154,187	2,933	4073	64,092	93,028
37	OPUC Order #12-226					
38	Siemens Long Term Deferred Rate Base (182410)	7,749,517	0	4073	431,487	7,318,030
39	IPUC Order #33420 (Amort period 01/16 thru 12/43)					
40	Siemens Long Term Deferred Rate Based (182411)	11,563,839	0	4073	643,867	10,919,972
41	IPUC Order #33420 (Amort period 01/16 thru 12/43)					
42	Siemens Long Term Deferred Rate Base (182412)	324,946	23,079	4073	42,921	305,104
43	OPUC Order #15-387 (Amort period 01/16 thru 12/36)					
44	Siemens Long Term Deferred Rate Based (182413)	432,474	0	4073	39,316	393,158
45	OPUC Order #15-387 (Amort period 01/16 thru 12/36)					
46	Siemens Long Term Interest Reserve (182414)	(274,489)	0	4190	23,080	(297,569)
47	Valmy Deferrals - ID (182430, 182432, 182435)	81,218,127	24,830,978	Various	21,218,185	84,830,920
48	IPUC Order #33771					
49	Valmy Decomm Oregon (182436)	(451,575)	772,471	400	1,211,316	(890,420)
50	OPUC Order #17-235 (Amort period 06/17 thru 12/25)					
51	PCA Deferral Idaho (multiple 182 accounts)	10,672,020	0	254	10,672,020	0
52	IPUC Order Pending (Amort period 06/26 thru 05/27)					

53	Mark-to-Market Long Term (182333)	11,808,135	4,751,469		0	16,559,604
54	Wildfire Mitigation-ID (182310)	40,349,931	28,764,036	1823	54,819,901	14,294,066
55	IPUC Order #35077					
56	Cloud Computing (182315)	1,322,509	2,145,195	4073	290,881	3,176,823
57	IPUC Order #34707					
58	Bridger Decommissioning (multiple 182 accounts)	147,450,977	35,064,562	Various	17,854,962	164,660,577
59	IPUC Order #35423					
60	Wildfire Mitigation Amort (182311)	22,867,052	55,554,596	4073	3,811,175	74,610,473
61	IPUC Order #36042 (Amort period 01/24-12/30)					
62	WRAP Deferral (182345)	635,221	456,886		0	1,092,107
63	IPUC Order #35920					
64	Capital leases (182300)	0	3,243,924		0	3,243,924
65	BPA Credit Idaho (254401, 254403)	0	24,086,396	Various	22,429,378	1,657,018
66	OPUC Advice #15-13					
67	BPA Credit Oregon (254402, 254404)	0	852,402	Various	867,302	(14,900)
68	OPUC Advice #15-11					
69	OR Bill Discount (254010)	0	710,734	1823	5,439	705,295
70	OPUC Order #25-121					
71	Minor Items (5)	174,636	299,148	Various	199,319	274,465
44	TOTAL	1,499,536,713	358,075,496		293,153,324	1,564,458,885

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

MISCELLANEOUS DEFERRED 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	Prepaid Credit Facility (186025) Multiple amortization periods	1,407,735	316,000	Various	342,101	1,381,634
2	Prepaid Services (LT) (186052) Multiple amortization periods	4,711,054	9,401	Various	953,929	3,766,526
3	Workers Compensation (186121)	1,124,448	134,020		0	1,258,468
4	Prepaid ROW (LT) (186160) Multiple amortization periods	355,128	0	401	43,901	311,227
5	CARB Inventory (186650)	553,675	0	158.1	553,675	0
6	Coal Royalties/Fly Ash (186709) Amortization through 12/29	305,084	0	151	199,259	105,825
7	Stable Value Life Inv (186719)	82,029,128	12,995,333		0	95,024,461
8	Security Plan Net Insurance Asset 186720	5,532,450	70,414		0	5,602,864
9	Retiree Medical-COLI (186726)	4,500,647	179,753	4262	1,770	4,678,630
10	American Falls Water Rts (186727)	86,835	0	401	86,835	0
11	American Falls Bond Refi (186770)	8,001	0	401	8,001	0
12	Regulatory Reserves (186800)	(1,559,879)	0	Various	2,471,234	(4,031,113)
13	Prepaid Service Contract (186255) Multiple amortization periods	76,926	129,357		0	206,283
14	Construction Studies (186623)	146,578	6,583,531	131	5,950,845	779,264
15	Regulatory Offsets (186100)	7,835,137	3,247,545		0	11,082,682
16	Minor Items (3)	17,073	598,120	Various	610,478	4,715
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	107,130,020				120,171,466

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Construction Advances	5,902,092	5,671,487
3	Postretirement Benefits	559,581	249,988
4	USBR-American Falls O&M Costs Settlement	157,337	188,439
5	Customer Deposits	0	13,015,080
6	Non-VEBA Pension and Benefits	(1,028,744)	(1,118,239)
7	Covid Deferral	(17,500)	0
8	Executive Deferred Compensation	180,985	225,099
9	Stock Based Compensation	3,009,565	3,057,143
10	Pension Expense-Oregon	4,852,000	4,904,968
11	Bridger Revenue Deferral	817,132	578,888
12	Asset Retirement Obligation (ARO)	1,572,308	1,525,780
13	Incentive Deferral-Profit Sharing-Not in Rates	4,665,165	4,698,430
14	OR Reconnect Fees Adv	4,496	0
15	Tax Reform Regulatory Stipulation	10,879,145	11,118,714
16	PCA Coal Usage Reserve	208,662	316,756
17	WRAP Deferral	(163,506)	0
18	OR Rate Mitigation	(13,401)	0
19	Rate Case Disallowance	734,348	639,903
20	Unrealized Loss on Investments	1,031	1,003
21	Prov for Rate Refund-HC Relicensing (AFUDC)	64,592,272	70,326,312
22	VEBA-Post Retirement Benefits	12,521,626	13,456,314
23	Deferred Idaho ITC	42,548,544	53,664,740
7	Other	137,225,163	(a)123,528,416
8	TOTAL Electric (Enter Total of lines 2 thru 7)	289,208,301	306,049,221
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	0	0
17.1	Other Non Electric (See footnote)	21,669,571	(b)21,276,931
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	310,877,872	327,326,152

Notes

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Line No.: 7	Beginning Balance	Ending Balance
Pension-FAS 158	11,207,263	3,293,801
Regulatory Liability-FAS 109	127,634,245	121,488,896
Minimum Pension Liability	4,745,704	4,989,199
Postretirement Plan-FAS 158	<u>(6,362,048)</u>	<u>(6,243,480)</u>
Total Other	137,225,164	123,528,416

(b) Concept: AccumulatedDeferredIncomeTaxes

Line No.: 17	Beginning Balance	Ending Balance
CIAC as Taxable inc Closed to nonutility Plant	78,534	76,365
Senior Management Security Plan	<u>21,591,037</u>	<u>21,200,566</u>
Total Non Electric	21,669,571	21,276,931

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)
1	Common Stock (Account 201)					
2	Account 201					
3	Common Stock all of which is held by IdaCorp, Inc. and not traded	50,000,000	2.5		39,150,812	97,877,030
4	Account 204 - None					
12	Total	50,000,000			39,150,812	97,877,030
13	Preferred Stock (Account 204)					
14						
15						
16						
17	Total					0

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)	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	Account 201				
3	Common Stock all of which is held by IdaCorp, Inc. and not traded				
4	Account 204 - None				
12	Total				
13	Preferred Stock (Account 204)				
14					
15					
16					
17	Total				

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2026-04-13	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

Other Paid-in Capital

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

- a. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
- b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
- c. Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
- d. Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Donations Received from Stockholders (Account 208)	
2	Beginning Balance Amount	0
3	Increases (Decreases) from Sales of Donations Received from Stockholders	0
4	Ending Balance Amount	0
5	Reduction in Par or Stated Value of Capital Stock (Account 209)	
6	Beginning Balance Amount	0
7	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	0
8	Ending Balance Amount	0
9	Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)	
10	Beginning Balance Amount	0
11	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	0
12	Ending Balance Amount	0
13	Miscellaneous Paid-In Capital (Account 211)	
14	Beginning Balance Amount	0
15	Increases (Decreases) Due to Miscellaneous Paid-In Capital	0
16	Ending Balance Amount	0
17	Other Paid in Capital	
18	Beginning Balance Amount	0
19	Increases (Decreases) in Other Paid-In Capital	0
20	Ending Balance Amount	0
40	Total	0

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)
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	Increases (Decreases) Due to Miscellaneous Paid-In Capital
16	Ending Balance Amount
17	Other Paid in Capital
18	Beginning Balance Amount
19	Increases (Decreases) in Other Paid-In Capital
20	Ending Balance Amount
40	Total

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	2,096,925
22	TOTAL	2,096,925

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)
1	Bonds (Account 221)					
2	4.00% Series due 2043	221101	75,000,000		741,728	0
3	3.65% Series Due 2045	221107	250,000,000		2,559,510	0
4	4.20% Series Due 2048	221110	450,000,000		4,629,516	(31,654,900)
5	4.99% PRP Due 2032	221111	23,000,000		169,158	0
6	5.06% PRP Due 2042	221112	25,000,000		183,842	0
7	5.06% PRP Due 2043	221113	60,000,000		441,200	0
8	5.20% PRP Due 2053	221114	62,000,000		455,883	0
9	5.875% Series due 2034	221116	55,000,000		585,759	0
10	6.00% Series due 2032	221133	100,000,000		1,191,216	0
11	5.30% Series Due 2035	221134	60,000,000		3,849,739	0
12	5.50% Series due 2033	221135	70,000,000		728,701	0
13	5.20% Series due 2034	221137	300,000,000		2,281,598	0
14	6.30% Series due 2037	221141	140,000,000		1,500,031	0
15	6.25% Series due 2037	221142	100,000,000		1,227,490	0
16	5.50% Series due 2034	221145	50,000,000		524,419	0
17	4.85% Series Due 2040	221146	100,000,000		1,284,871	0
18	4.30% Series Due 2042	221147	75,000,000		802,240	0
19	4.05% Series Due 2046	221148	120,000,000		1,321,383	0
20	1.90% Series Due 2030	221149	80,000,000		980,949	0
21	5.50% Series Due 2053	221222	400,000,000		4,381,222	0
22	5.80% Series Due 2054	221333	350,000,000		3,769,611	0

23	Sweetwater 1.7% Variable due 2026	221335	116,300,000		908,982	0
24	5.70% Series Due 2055	221224	400,000,000		4,448,420	0
25	Subtotal		3,461,300,000		38,967,468	(31,654,900)
26	Reacquired Bonds (Account 222)					
27	Subtotal		0		0	0
28	Subtotal					
29	Advances from Associated Companies (Account 223)					
30	Subtotal		0		0	0
31	Subtotal					
32	Other Long Term Debt (Account 224)					
33	OTHR LTD - AM FALLS BOND OBLIG	224200	19,885,000		309,011	0
34	Subtotal		19,885,000		309,011	0
33	TOTAL		3,481,185,000			

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)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)
1	Bonds (Account 221)					
2	4.00% Series due 2043	194,250	04/08/2013	04/01/2043	04/08/2013	04/01/2043
3	3.65% Series Due 2045	1,715,000	03/06/2015	03/01/2045	03/06/2015	03/01/2045
4	4.20% Series Due 2048	814,000	03/16/2018	03/01/2048	03/16/2018	03/01/2048
5	4.99% PRP Due 2032	0	12/22/2022	12/22/2032	12/22/2022	12/22/2032
6	5.06% PRP Due 2042	0	12/22/2022	12/22/2042	12/22/2022	12/22/2042
7	5.06% PRP Due 2043	0	03/08/2023	03/08/2043	03/08/2023	03/08/2043
8	5.20% PRP Due 2053	0	03/08/2023	03/15/2053	03/08/2023	03/15/2053
9	5.875% Series due 2034	748,000	08/16/2004	08/15/2034	08/16/2004	08/15/2034
10	6.00% Series due 2032	544,000	11/15/2002	11/15/2032	11/15/2002	11/15/2032
11	5.30% Series Due 2035	408,600	08/26/2005	08/15/2035	08/26/2005	08/15/2035
12	5.50% Series due 2033	36,400	05/13/2003	04/01/2033	05/13/2003	04/01/2033
13	5.20% Series due 2034	186,000	08/12/2024	08/15/2034	08/12/2024	08/15/2034
14	6.30% Series due 2037	278,600	06/22/2007	06/15/2037	06/22/2007	06/15/2037
15	6.25% Series due 2037	268,000	10/18/2007	10/15/2037	10/18/2007	10/15/2037
16	5.50% Series due 2034	383,500	03/26/2004	03/15/2034	03/26/2004	03/15/2034
17	4.85% Series Due 2040	170,000	08/30/2010	08/15/2040	08/30/2010	08/15/2040
18	4.30% Series Due 2042	49,500	04/13/2012	04/01/2042	04/13/2012	04/01/2042
19	4.05% Series Due 2046	309,600	03/10/2016	03/01/2046	03/10/2016	03/01/2046
20	1.90% Series Due 2030	328,000	06/22/2020	07/15/2030	06/22/2020	07/15/2030
21	5.50% Series Due 2053	3,772,000	03/14/2023	03/15/2053	03/14/2023	03/15/2053
22	5.80% Series Due 2054	3,234,000	09/11/2023	04/01/2054	09/11/2023	04/01/2054
23	Sweetwater 1.7% Variable due 2026	0	08/21/2019	07/15/2026	08/21/2019	07/15/2026
24	5.70% Series Due 2055	3,072,000	03/13/2025	03/15/2055	03/13/2025	03/15/2055
25	Subtotal	16,511,450				

26	Reacquired Bonds (Account 222)					
27	Subtotal	0				
28	Subtotal					
29	Advances from Associated Companies (Account 223)					
30	Subtotal	0				
31	Subtotal					
32	Other Long Term Debt (Account 224)					
33	OTHR LTD - AM FALLS BOND OBLIG	0	04/26/2000	02/01/2025	04/26/2000	02/01/2025
34	Subtotal	0				
33	TOTAL					

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)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)		
2	4.00% Series due 2043	75,000,000	3,000,000
3	3.65% Series Due 2045	250,000,000	9,125,000
4	4.20% Series Due 2048	450,000,000	18,891,006
5	4.99% PRP Due 2032	23,000,000	1,147,700
6	5.06% PRP Due 2042	25,000,000	1,265,000
7	5.06% PRP Due 2043	60,000,000	3,036,000
8	5.20% PRP Due 2053	62,000,000	3,224,000
9	5.875% Series due 2034	55,000,000	3,231,250
10	6.00% Series due 2032	100,000,000	6,000,000
11	5.30% Series Due 2035	60,000,000	3,180,000
12	5.50% Series due 2033	70,000,000	3,850,000
13	5.20% Series due 2034	300,000,000	15,600,000
14	6.30% Series due 2037	140,000,000	8,820,000
15	6.25% Series due 2037	100,000,000	6,250,000
16	5.50% Series due 2034	50,000,000	2,750,000
17	4.85% Series Due 2040	100,000,000	4,850,000
18	4.30% Series Due 2042	75,000,000	3,225,000
19	4.05% Series Due 2046	120,000,000	4,860,000
20	1.90% Series Due 2030	80,000,000	1,520,000
21	5.50% Series Due 2053	400,000,000	22,000,000
22	5.80% Series Due 2054	350,000,000	20,300,000
23	Sweetwater 1.7% Variable due 2026	116,300,000	1,977,100
24	5.70% Series Due 2055	400,000,000	18,240,000
25	Subtotal	3,461,300,000	166,342,056
26	Reacquired Bonds (Account 222)		

27	Subtotal	0	0
28	Subtotal	0	
29	Advances from Associated Companies (Account 223)		
30	Subtotal	0	0
31	Subtotal		
32	Other Long Term Debt (Account 224)		
33	OTHR LTD - AM FALLS BOND OBLIG	0	0
34	Subtotal	0	0
33	TOTAL	3,461,300,000	166,342,056

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: BondsPrincipalAmountIssued

Additional \$230 million of 4.20% bonds due 3/1/2048 issued on 4/3/2020 with a premium of \$31,654,900, bringing total 4.20% series outstanding to \$450 million.

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	315,861,850
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	4005-AVOIDED COST	36,768,761
6	4021-ENGINEERING FEES - TAXABLE - ACCT 107	372,095
7	5026-CUSTOMER DEPOSITS	52,000,000
9	Deductions Recorded on Books Not Deducted for Return	
10	5008-GAIN/LOSS ON REACQUIRED DEBT	193,599
11	5014-VACATION ACCRUAL	2,000,000
12	5023-PENSION EXPENSE	2,991,207
13	5024-NON-DEDUCTIBLE MEALS	893,000
14	5035-PCA EXPENSE DEFERRAL	10,672,020
15	5053-STOCK BASED COMPENSATION	2,605,794
16	5058-FIXED COST ADJUSTMENT	10,906,313
17	5061-PENSION EXPENSE - OREGON	747,099
18	5067-ASSET RETIREMENT OBLIGATION (ARO)	2,119
19	5071-INCENTIVE DEFERRAL-PROFIT SHARING-NOT IN RATES	1,214,317
20	5078-TAX REFORM REGULATORY STIPULATION	2,157,804
21	5083-PCA COAL USAGE RESERVE	454,904
22	5087-OR OTHER RA-2026 RFP IE-UM2272 24-050	385,311
23	5504-NON-DEDUCTIBLE POLITICAL EXPENSES	1,147,222
24	5505-SMSP - NET	822,743
25	5510-FINES & PENALTIES - OPERATING	60,000
26	5538-STOCK BASED COMP - STOCK	1,426,441
27	7010-PROV FOR RATE REFUND - HC RELICENSING (AFUDC)	30,038,085
28	8001-VEBA - POST RETIREMENT BENEFITS	1,102,123
29	8009-DEPR TIMING DIFF - OPERATING - FEDERAL	148,669,469
30	8041-AMERICAN FALLS REFINANCE - OLD COSTS	8,001
31	8042-GAIN/LOSS ON REACQUIRED DEBT	2,243,074

32	8703-IPCO-162(m) \$1M THRESHOLD	6,429,753
33	9009-VALMY1 BOOK BASIS ADJUSTMENT	3,081,950
34	CM 39-ITC BASIS REDUCTION - NOT IN PLANT	17,500,000
14	Income Recorded on Books Not Included in Return	
15	Total Federal and State tax income on books	13,260,878
16	4003-CONSTRUCTION ADVANCES	1,098,119
17	4013-CIAC - TAXABLE - ACCT 107	5,393,122
18	5501-SMSP - INSURANCE COSTS	13,065,746
19	7501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES	2,248,635
20	7502-ALLOWANCE FOR OFUDC	62,488,668
21	7503-ALLOWANCE FOR BFUDC	36,210,634
19	Deductions on Return Not Charged Against Book Income	
20	5001-BAD DEBT EXPENSE	1,274,209
21	5010-POSTEMPLOYMENT BENEFITS-SFAS112	1,543,032
22	5017-INJURIES AND DAMAGES	800,000
23	5022-263A CAPITALIZED OVERHEADS	10,000,000
24	5028-OREGON OPERATING PROPERTY TAX ADJ	146,947
25	5043-AMERICAN FALLS - FALLING WATER CONTRA	50,294
26	5045- WILDFIRE MITIGATION 35077 DEFERRAL	25,687,556
27	5052-AMORTIZATION OF ACCOUNT 181	288,386
28	5060-OREGON - PCAM	105,811
29	5064-BRIDGER REVENUE DEFERRAL	584,695
30	5066-BOARDMAN DECOMMISSION	1,647,553
31	5070-INCENTIVE DEFERRAL-CRI & RELIABILITY-INCLUDED IN RATES	771,336
32	5077-VALMY DEPRECIATION ADJUSTMENT	3,880,730
33	5081-EIM PCA OFFSET ESTIMATE	3,247,545
34	5082-BRIDGER DEPRECIATION ADJUST - 283	2,975,915
35	5084-WRAP DEFERRAL -283	456,886
36	5531-RATE CASE DISALLOWANCES	296,299
37	8021-CONSERVATION EXPENSES - WAQC	320,828
38	8034-REMOVAL COSTS	27,175,434
39	8072-RELICENSING - LABOR COSTS DEDUCTED - ACCT 107	1,720,000
40	8073-REPAIRS DEDUCTION	115,000,000
41	8077-PREPAID INSURANCE & OTHER EXPENSES	4,000,000
42	8702-STOCK BASED COMP - DIVIDENDS	721,371
43	8705-OR CAT	338,212
44	STATE INCOME TAX DEDUCTED ON FEDERAL RETURN	11,844,198
27	Federal Tax Net Income	304,112,015
28	Show Computation of Tax:	
29	Line 29: Tentative Federal Tax @ 21%	63,863,523

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

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

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR	
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)
1	Federal	Income Tax			(14,776,213)	0
2	State	Income Tax	Idaho		1,779,894	0
3	State	Income Tax	Oregon		468,715	0
4	Other	Income Tax	Other		488,680	0
5	Federal	Other Taxes			(139,385)	0
6	Other	Other Taxes	Other		(998)	0
7	State	Other State Tax	Idaho		11,195	0
8	State	Other State Tax	Idaho		89,248	0
9	State	Other State Tax	Nevada		7,555	0
10	State	Other State Tax	Idaho		0	0
11	State	Other State Tax	Oregon		0	0
12	State	Other State Tax	Wyoming		0	0
13	State	Other State Tax	Oregon		0	0
14	State	Other State Tax	Oregon		0	888
15	State	Other License And Fees Tax	Idaho		0	0
16	Federal	Unemployment Tax			(2,252)	0
17	State	Unemployment Tax	Idaho		(2,192)	0
18	State	Unemployment Tax	Oregon		(28)	0
19	State	Property Tax	Idaho		5,965,592	0
20	State	Property Tax	Washington		4,104	0
21	State	Property Tax	Idaho		0	0

22	State	Property Tax	Montana		173,816	0
23	State	Property Tax	Wyoming		643,480	0
24	State	Property Tax	Oregon		0	3,015,228
25	State	Property Tax	Nevada		0	125,949
26	State	Franchise Tax	Oregon		231,059	0
27	Other	Payroll Tax	Other		0	0
40	TOTAL				(5,057,730)	3,142,065

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

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

Line No.	Kind of Tax (See Instruction 5) (a)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR	
					Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)
1	Federal	25,201,425	12,326,075	0	(1,900,863)	0
2	State	5,658,538	7,522,044	0	(83,612)	0
3	State	1,101,828	1,160,052	0	410,491	0
4	Other	(148,436)	23,301	0	316,943	0
5	Federal	22,681,476	22,721,865	0	(179,774)	0
6	Other	0	(6,016)	(5,018)	0	0
7	State	16,185	19,271	0	8,109	0
8	State	1,723,751	1,734,845	0	78,154	0
9	State	(7,152)	403	0	0	0
10	State	3,570,673	3,570,673	0	0	0
11	State	72,521	72,521	0	0	0
12	State	4,339	4,339	0	0	0
13	State	197,468	337,843	140,375	0	0
14	State	1,802	1,828	0	0	914
15	State	150	150	0	0	0
16	Federal	98,958	98,890	0	(2,184)	0
17	State	274,059	274,070	0	(2,203)	0
18	State	76,801	76,824	0	(51)	0
19	State	14,351,282	13,866,757	0	6,450,117	0
20	State	4,568	4,336	0	4,336	0
21	State	181,870	179,727	0	2,143	0
22	State	391,143	369,697	0	195,262	0
23	State	1,496,160	1,391,559	0	748,081	0
24	State	6,179,430	6,326,377	0	0	3,162,175
25	State	236,203	336,230	0	0	225,976

26	State	979,388	979,911	0	230,536	0
27	Other	(23,131,294)	0	23,131,294	0	0
40	TOTAL	61,213,136	73,393,572	23,266,651	6,275,485	3,389,065

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

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

Line No.	Kind of Tax (See Instruction 5) (a)	DISTRIBUTION OF TAXES CHARGED			
		Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	Federal	16,727,563	0	0	8,473,862
2	State	4,133,319	0	0	1,525,219
3	State	1,346,183	0	0	(244,355)
4	Other	(181,446)	0	0	33,010
5	Federal	22,681,476	0	0	0
6	Other	0	0	0	0
7	State	0	0	0	16,185
8	State	1,723,751	0	0	0
9	State	(7,152)	0	0	0
10	State	3,570,673	0	0	0
11	State	72,521	0	0	0
12	State	4,339	0	0	0
13	State	197,468	0	0	0
14	State	0	0	0	1,802
15	State	150	0	0	0
16	Federal	98,958	0	0	0
17	State	274,059	0	0	0
18	State	76,801	0	0	0
19	State	14,346,367	0	0	4,915
20	State	4,568	0	0	0
21	State	181,870	0	0	0
22	State	391,143	0	0	0
23	State	1,496,160	0	0	0
24	State	5,192,288	0	0	987,142
25	State	236,203	0	0	0

26	State	979,388	0	0	0
27	Other	(23,131,294)	0	0	0
40	TOTAL	50,415,356	0	0	10,797,780

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income	
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)
1	Electric Utility					
2	3%					
3	4%				420.101	0
4	7%					
5	10%				420.101	0
6	Other - Federal	146,947,318	411.401	35,038,323		14,225,352
7	Other - State	83,374,783	411.402	17,908,409	411.402/420.102	33,319,367
8	TOTAL Electric (Enter Total of lines 2 thru 7)	230,322,101		52,946,732		47,544,719
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)					
10	11%				420.101	0
11	30%	146,947,318	411.401	35,038,323	411.401	14,225,352
12	Total Line No. 6	146,947,318		35,038,323		14,225,352
13	State of Idaho	83,374,783	411.402	17,908,409	411.402/420.102	33,319,367
47	OTHER TOTAL	230,322,101		52,946,732		47,544,719
48	GRAND TOTAL	230,322,101		52,946,732		47,544,719

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)	Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
1	Electric Utility				
2	3%				
3	4%		0		
4	7%		0		
5	10%		0		
6	Other - Federal	0	167,760,289		
7	Other - State		67,963,825	2.50	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	0	235,724,114		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)				
10	11%		0		
11	30%		167,760,289	10.33	
12	Total Line No. 6	0	167,760,289		
13	State of Idaho		67,963,825		
47	OTHER TOTAL	0	235,724,114		
48	GRAND TOTAL	0	235,724,114		

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

<p>(a) Concept: AccumulatedDeferredInvestmentTaxCreditsAllocationToIncomeAmount</p> <p>Includes 33,319,637 to account 420.102.</p>
<p>(b) Concept: AccumulatedDeferredInvestmentTaxCreditsAllocationToIncomeAmount</p> <p>Includes 33,319,637 to account 420.102.</p>

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than \$100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	PTP Transmission Deposits 253201	6,450,758	131	3,743,952	2,277,561	4,984,367
2	Cogen Deposits 253360	147,000		0	0	147,000
3	Sho-Ban Scholarships 253480	52,500	242	15,000	0	37,500
4	Amortization period 01/05-12/27					
5	Operations Accruals 253550	32,256,010	131	4,124,164	56,150,345	84,282,191
6	Postretirement Benefits 253960	2,541,826	401	1,543,032	0	998,794
7	Directors Deferred Compensation (253970-253999)	3,130,301	131	202,000	230,267	3,158,568
47	TOTAL	44,578,395		9,628,148	58,658,173	93,608,420

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

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

1. Report the information called for below concerning the respondent's accounting for deferred income taxes 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
			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)
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 - 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 End of Year (k)
		...	Credits		
		Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)				
2	Electric				
3	Defense Facilities				
4	Pollution Control Facilities				
5	Other				
5.1	Other				
5.2	Other				
8	TOTAL Electric (Enter Total of lines 3 thru 7)				
9	Gas				
10	Defense Facilities				
11	Pollution Control Facilities				
12	Other				
12.1	Other				
12.2	Other				
15	TOTAL Gas (Enter Total of lines 10 thru 14)				
16	Other				
16.1	Other				
16.2	Other				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)				
18	Classification of TOTAL				
19	Federal Income Tax				
20	State Income Tax				
21	Local Income Tax				

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS
			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)
1	Account 282						
2	Electric	197,682,390	3,513,823	21,401,477	0	0	
3	Gas	0					
4	Other (Specify)	0					
5	Total (Total of lines 2 thru 4)	197,682,390	3,513,823	21,401,477	0	0	
6	Non-Operating Property						
7	Other - Regulatory Asset for Income Taxes	811,053,690					
8	Like Kind Exchange - Reclass Non-Rate Base	3,857,537					282
9	TOTAL Account 282 (Total of Lines 5 thru 8)	1,012,593,617	3,513,823	21,401,477	0	0	
10	Classification of TOTAL						
11	Federal Income Tax	801,830,814	3,490,122	21,257,796			
12	State Income Tax	210,762,803	23,701	143,681			
13	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 relating to property not subject to accelerated amortization.
2. For other (Specify), include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	...			Balance at End of Year (k)
		...	Credits		
		Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282				
2	Electric		282/254	9,945,368	189,740,104 ^(a)
3	Gas				0
4	Other (Specify)				0
5	Total (Total of lines 2 thru 4)	0		9,945,368	189,740,104
6	Non-Operating Property				
7	Other - Regulatory Asset for Income Taxes		182	10,291,832	821,345,522
8	Like Kind Exchange - Reclass Non-Rate Base	221,698			3,635,839
9	TOTAL Account 282 (Total of Lines 5 thru 8)	221,698		20,237,200	1,014,721,465
10	Classification of TOTAL				
11	Federal Income Tax		182/254	43,975,133	828,038,273
12	State Income Tax		182	(23,959,631)	186,683,192
13	Local Income Tax				

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Line No.	Account (a)	2025	Changes during Year				Adjustments Debits	
		Beginning Balance (b)	DR to (c)	CR to (d)	DR to (e)	CR to (f)	Acct. credited (g)	Amount (h)
Line 2:	Depreciation Timing Diff-Operating	373,187,071	2,002,481	21,323,337	-	-	-	-
	Like Kind Exchange - Reclass Non-Rate Base	(3,857,537)	-	-	-	-	-	-
	Excess Deferred Tax on Depreciation (Reg Liab)	(137,903,191)	-	-	-	-	-	-
4013	CIAC-Taxable-Acct 107	(46,283,009)	1,255,065	-	-	-	-	-
4021	Engineering Fees-Taxable-Acct 107	(876,648)	-	78,140	-	-	-	-
8072	Intangible-Labor Costs Deducted-Acct 107	<u>13,415,704</u>	<u>256,277</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
	TOTAL Line 2	197,682,390	3,513,823	21,401,477	0	0		0

Line No.	Account (a)	Adjustments Credits		2025
		Acct. debited (i)	Amount (j)	Ending Balance (k)
Line 2:	Depreciation Timing Diff-Operating		-	353,866,215
	Like Kind Exchange - Reclass Non-Rate Base	282111	221,698	(3,635,839)
	Excess Deferred Tax on Depreciation (Reg Liab)	254967	9,723,670	(128,179,521)
4013	CIAC-Taxable-Acct 107		-	(45,027,944)
4021	Engineering Fees-Taxable-Acct 107		-	(954,788)
8072	Intangible-Labor Costs Deducted-Acct 107		<u>-</u>	<u>13,671,981</u>
	TOTAL Line 2		9,945,368	189,740,104

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR			
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)
1	Account 283					
2	Electric					
3	Other Electric	141,437,326	10,558,503	11,286,277	0	0
4	Other	4,845,216	0	0	0	0
9	TOTAL Electric (Total of lines 3 thru 8)	146,282,542	10,558,503	11,286,277	0	0
10	Gas					
11						
12						
13						
14						
15						
16						
17	TOTAL Gas (Total of lines 11 thru 16)	0	0	0	0	0
18	TOTAL Other	(102,405)	0	0	43,448	299
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	146,180,137	10,558,503	11,286,277	43,448	299
20	Classification of TOTAL					
21	Federal Income Tax	112,126,044	8,352,330	4,803,047.59	31,272	(80)
22	State Income Tax	34,054,093	2,206,173	6,483,229	12,176	379
23	Local Income Tax					
NOTES						

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)	ADJUSTMENTS				Balance at End of Year (k)
		Debits		Credits		
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283					
2	Electric					
3	Other Electric		0		0	140,709,552
4	Other		0	190	(7,794,895)	(2,949,679)
9	TOTAL Electric (Total of lines 3 thru 8)		0		(7,794,895)	137,759,873
10	Gas					
11						
12						
13						
14						
15						
16						
17	TOTAL Gas (Total of lines 11 thru 16)		0		0	0
18	TOTAL Other		0		0	(59,256)
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)		0		(7,794,895)	137,700,617
20	Classification of TOTAL					
21	Federal Income Tax			190	(6,064,437)	109,642,241
22	State Income Tax			190	(1,730,458)	28,058,376
23	Local Income Tax					
NOTES		...				
		...				

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

Line No.	Account (a)	2025	Changes during Year			Adjustments		Amount h
		Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Debits Acct. credited g	
Line 3:								
4024	Renewable Energy Certificates (REC) Sales	2,651,098	-	623,179	-	-	-	-
4501	Royalty Income	126,387	-	50,027	-	-	-	-
5008	Gain/Loss on Reacquired Debt	78,028	-	50,612	-	-	-	-
5015	MSC C&A Liab-Delivery	-	7,290	-	-	-	-	-
5023	Pension Expense	70,870,450	-	2,706,280	-	-	-	-
5035	PCA Expense	2,746,978	-	2,746,978	-	-	-	-
5045	Wildfire Mitigation 35077 Deferral	16,272,052	6,429,338	449,473	-	-	-	-
5057	Intervenor Funding Orders	88,663	178	2,449	-	-	-	-
5058	Fixed Cost Adjustment	4,571,708	-	2,856,022	-	-	-	-
5060	Oregon - PCAM	-	26,483	-	-	-	-	-
5066	Boardman Decommission	(891,461)	1,009,031	-	-	-	-	-
5074	Valmy Settlement Adjustment	-	-	-	-	-	-	-
5077	Valmy Depreciation Adjustment	14,619,731	971,309	403,832	-	-	-	-
5079	Community Solar Deferral	70,180	-	16,142	-	-	-	-
5081	EIM PCA Offset Estimate	2,016,764	828,367	55,708	-	-	-	-
5082	Bridger Depreciation Adjust - 283	27,294,540	744,842	753,940	-	-	-	-
5084	WRAP Deferral	-	273,343	-	-	-	-	-
5085	OR Rate Mitigation	-	13,031	-	-	-	-	-
5086	RA Nat Gas Maint	-	-	315,435	-	-	-	-
5087	OR Other RA-2026 RFP IE - UM272 24-050	-	10,958	96,440	-	-	-	-
7013	Langley Revenue Accrual	88,588	-	49,997	-	-	-	-
8020	Conservation Expenses	(298,556)	209,608	-	-	-	-	-
8021	Conservation Expenses - WAQC Co	-	80,300	-	-	-	-	-
8082	Siemens LTP Contract	162,130	16,738	4,478	-	-	-	-
8082	Prepaid Credit Facility	224,385	-	53,079	-	-	-	-
8083	Siemens OR DRB Interest Reserve	(64,043)	1,770	6,429	-	-	-	-
8704	Boardman Removal Costs	679,997	23,987	18,783	-	-	-	-
8706	OR Annual Reg Exp	41,637	-	26,994	-	-	-	-
N/A	Oregon CAT Deferral	88,070	(88,070)	-	-	-	-	-
	TOTAL Line 3	141,437,326	10,558,503	11,286,277	-	-	-	-

Line No.	Account (a)	Adjustments Credits		2025 Ending Balance k
		Acct. debited i	Amount j	
Line 3:				
4024	Renewable Energy Certificates (REC) Sales	-	-	2,027,919
4501	Royalty Income	-	-	76,360
5008	Gain/Loss on Reacquired Debt	-	-	27,416
5015	MSC C&A Liab-Delivery	-	-	7,290
5023	Pension Expense	-	-	68,164,170
5035	PCA Expense	-	-	-
5045	Wildfire Mitigation 35077 Deferral	-	-	22,251,917
5057	Intervenor Funding Orders	-	-	86,392
5058	Fixed Cost Adjustment	-	-	1,715,686
5060	Oregon - PCAM	-	-	26,483
5066	Boardman Decommission	-	-	117,570
5074	Valmy Settlement Adjustment	-	-	-
5077	Valmy Depreciation Adjustment	-	-	15,187,208
5079	Community Solar Deferral	-	-	54,038
5081	EIM PCA Offset Estimate	-	-	2,789,423
5082	Bridger Depreciation Adjust - 283	-	-	27,285,442
5084	WRAP Deferral	-	-	273,343
5085	OR Rate Mitigation	-	-	13,031
5086	RA Nat Gas Maint	-	-	(315,435)
5087	OR Other RA-2026 RFP IE - UM272 24-050	-	-	(85,482)
7013	Langley Revenue Accrual	-	-	38,591
8020	Conservation Expenses	-	-	(88,948)
8021	Conservation Expenses - WAQC Co	-	-	80,300
8082	Siemens LTP Contract	-	-	174,390
8082	Prepaid Credit Facility	-	-	171,306
8083	Siemens OR DRB Interest Reserve	-	-	(68,702)
8704	Boardman Removal Costs	-	-	685,201
8706	OR Annual Reg Exp	-	-	14,643
N/A	Oregon CAT Deferral	-	-	-
	TOTAL Line 3	-	-	140,709,552

(b) Concept: AccumulatedDeferredIncomeTaxesOther

Line No.	Account (a)	2025	Changes during Year				Adjustments	Amount
		Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Debits Acct. credited g	
Line 8:	Pension-FAS 158	11,207,263	-	-	-	-	-	-
	Postretirement Plan-FAS 158	(6,362,047)	-	-	-	-	-	-
	TOTAL Line 8	4,845,216	-	-	-	-	-	-

Line No.	Account (a)	Adjustments Credits		Amount	2025 Ending Balance k
		Acct. debited i	Amount j		
Line 8:	Pension-FAS 158		190	(7,913,462)	3,293,801
	Postretirement Plan-FAS 158		190	118,567	(6,243,480)
	TOTAL Line 8		190	(7,794,895)	(2,949,679)

(c) Concept: AccumulatedDeferredIncomeTaxesOther

Line No.	Account (a)	2025	Changes during Year				Adjustments	Amount
		Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Debits Acct. credited g	
Line 18:	EDC-Unrealized Gain/Loss From Rabbit Trust	10,618	-	-	10,826	293	-	
	SMSP-Unrealized Gain/Loss From Rabbi Trust	(113,247)	-	-	32,618	-	-	
	Oregon Non-Op Prop Tax Adj	224	-	-	4	6	-	
	TOTAL Line 18	(102,405)	-	-	43,448	299	-	

Line No.	Account (a)	Adjustments Credits		Amount	2025 Ending Balance k
		Acct. debited i	Amount j		
Line 18:	EDC-Unrealized Gain/Loss From Rabbit Trust		-	-	21,151
	SMSP-Unrealized Gain/Loss From Rabbi Trust		-	-	(80,629)
	Oregon Non-Op Prop Tax Adj		-	-	222
	TOTAL Line 18		-	-	(59,256)

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Market to Market Short Term (254001)	0			3,080	3,080
2	IPUC Order #28661					
3	Oregon Solar Rider (254005)	561,663	401	4,219	183,497	740,941
4	OPUC Order #10-198					
5	BPA Credits - Idaho (254401, 254403)	4,004,042	1823	4,004,042	0	0
6	OPUC Advice #15-13					
7	BPA Credits - Oregon (254402, 254404)	163,049	1823	163,049	0	0
8	OPUC Advice #15-11					
9	Idaho Tax Settlement (254451)	42,265,521		0	2,157,805	44,423,326
10	IPUC Order #34071					
11	Bridger Depreciation (254800, 254801)	2,897,563	400	870,201	0	2,027,362
12	OPUC Order #12-296					
13	RL-WAQC CRYOVR (254901)	355,379	401	320,828	0	34,551
14	Unfunded Accum Def Income Tax (254966)	79,834,243	Various	2,568,266	1,430,303	78,696,280
15	RL-DEF INC TAX-ARAM (254967)	137,903,191	282	9,723,670	0	128,179,521
16	RL-DEF INC TAX-ARAM GROSS-UP (254968)	47,800,001	190	5,007,385	0	42,792,616
17	Boardman Decommissioning	5,075,007	Various	6,313,598	4,666,045	3,427,454
18	OPUC Order #12-235, IPUC Order #32457					
19	Market-to-Market Short Term (254203)	1,529,745	175	1,529,745	0	0
20	Oregon DSM Rider (254202)	1,706,318	Various	1,303,842	2,725,330	3,127,806
21	OPUC Advice #05-03					
22	Oregon Green Tags (254415)	805,595	Various	558,153	1,238,687	1,486,129
23	OPUC Order #11-086					
24	Oregon PCAM (182384, 182356)	3,143,338	Various	3,284,472	35,324	(105,810)
25	OPUC Order Pending					
26	Idaho DSM Rider (254201)	7,570,508	Various	28,945,938	34,740,692	13,365,262

27	IPUC Order #28661					
28	Natural Gas Plant Maint (182344)	1,260,278			513,088	1,773,366
29	IPUC Order #36042					
30	PCA Deferral Idaho (Multiple 182 accounts)	0	Various	18,881,842	71,003,339	52,121,497
31	AOCI Impact of Unfunded Pension Liability	0	Various	56,700,197	43,540,260	(13,159,937)
32	IPUC Order #30256 (182320)					
33	AOCI Impact of Postretirement Liability	0	Various	390,588	25,335,574	24,944,986
34	IPUC Order #30256 (182306)					
35	Minor Items (1)	5,438		5,438	0	0
41	TOTAL	336,880,879		140,575,474	187,573,024	383,878,430

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

Electric Operating Revenues

- 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.
- Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
- 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.
- 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.
- Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.
- 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.)
- See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
- For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
- 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)
1	Sales of Electricity					
2	(440) Residential Sales	708,143,132	700,402,010	6,010,290	5,963,609	554,211
3	(442) Commercial and Industrial Sales					
4	Small (or Comm.) (See Instr. 4)	588,284,867	589,288,117	6,366,016	6,302,525	97,672
5	Large (or Ind.) (See Instr. 4)	270,596,771	267,210,241	3,778,206	3,680,289	149
6	(444) Public Street and Highway Lighting	4,516,904	4,349,086	25,247	24,611	5,229
7	(445) Other Sales to Public Authorities					
8	(446) Sales to Railroads and Railways					
9	(448) Interdepartmental Sales					
10	TOTAL Sales to Ultimate Consumers	1,571,541,674	1,561,249,454	16,179,760	15,971,034	657,261
11	(447) Sales for Resale	124,539,480	142,669,958	2,896,549	2,817,443	
12	TOTAL Sales of Electricity	1,696,081,153	1,703,919,412	19,076,309	18,788,477	657,261
13	(Less) (449.1) Provision for Rate Refunds	15,119,961	8,225,395			
14	TOTAL Revenues Before Prov. for Refunds	1,680,961,192	1,695,694,017	19,076,309	18,788,477	657,261
15	Other Operating Revenues					
16	(450) Forfeited Discounts					
17	(451) Miscellaneous Service Revenues	7,270,508	6,838,793			
18	(453) Sales of Water and Water Power					
19	(454) Rent from Electric Property	21,888,792	19,472,366			
20	(455) Interdepartmental Rents					

21	(456) Other Electric Revenues	\$31,860,886	\$29,476,334			
22	(456.1) Revenues from Transmission of Electricity of Others	62,422,041	67,351,336			
23	(457.1) Regional Control Service Revenues					
24	(457.2) Miscellaneous Revenues					
25	Other Miscellaneous Operating Revenues					
26	TOTAL Other Operating Revenues	123,442,227	123,138,829			
27	TOTAL Electric Operating Revenues	1,804,403,419	1,818,832,846			

Line12, column (b) includes \$ (10,438,714) of unbilled revenues.

Line12, column (d) includes (33,417) MWH relating to unbilled revenues

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)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity	
2	(440) Residential Sales	539,849
3	(442) Commercial and Industrial Sales	
4	Small (or Comm.) (See Instr. 4)	96,648
5	Large (or Ind.) (See Instr. 4)	138
6	(444) Public Street and Highway Lighting	4,931
7	(445) Other Sales to Public Authorities	
8	(446) Sales to Railroads and Railways	
9	(448) Interdepartmental Sales	
10	TOTAL Sales to Ultimate Consumers	641,566
11	(447) Sales for Resale	
12	TOTAL Sales of Electricity	641,566
13	(Less) (449.1) Provision for Rate Refunds	
14	TOTAL Revenues Before Prov. for Refunds	641,566
15	Other Operating Revenues	
16	(450) Forfeited Discounts	
17	(451) Miscellaneous Service Revenues	
18	(453) Sales of Water and Water Power	
19	(454) Rent from Electric Property	
20	(455) Interdepartmental Rents	
21	(456) Other Electric Revenues	
22	(456.1) Revenues from Transmission of Electricity of Others	
23	(457.1) Regional Control Service Revenues	
24	(457.2) Miscellaneous Revenues	
25	Other Miscellaneous Operating Revenues	
26	TOTAL Other Operating Revenues	
27	TOTAL Electric Operating Revenues	

Line12, column (b) includes \$ (10,438,714) of unbilled revenues. ...

Line12, column (d) includes (33,417) MWH relating to unbilled revenues ...

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: MiscellaneousServiceRevenues

This amount consists of:

Service Establishment/Connection Charges: \$7,282,114

(Includes late and after hour charges)

Misc: -\$11,606

(b) Concept: OtherElectricRevenue

This amount consists of:

DSM Activity: \$30,480,049

Services: \$1,217,506

Misc. Under \$250,000: \$163,332

(c) Concept: MiscellaneousServiceRevenues

This amount consists of:

Service Establishment/Connection Charges: \$6,286,059

(Includes late and after hour charges)

Misc: \$552,734

(d) Concept: OtherElectricRevenue

This amount consists of:

DSM Activity: \$27,580,701

Services: \$1,161,215

Misc. Under \$250,000: -\$904

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	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					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					

33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	01 RESIDENTIAL	5,848,577	704,692,927	534,515	10,942	0.1205
2	03 Residential Master Meter	4,538	524,760	17	266,932	0.1156
3	04 Residential EW	0	0	0		
4	05 Residential TOD	18,129	2,106,024	1,029	17,620	0.1162
5	06 Residential On-Site Generation	166,878	20,600,660	18,650	8,948	0.1234
6	15 DUSK TO DAWN LIGHT	769	650,947	0		
7	Other	0	(13,267,902)	0		
41	TOTAL Billed Residential Sales	6,038,870	715,307,416	554,211	10,896	0.1185
42	TOTAL Unbilled Rev. (See Instr. 6)	(28,581)	(7,164,284)			0.2507
43	TOTAL	6,010,290	708,143,132	554,211	10,845	0.1178

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	07 GENERAL SERVICE	158,080	22,836,633	32,615	4,847	0.1445
2	08 GENERAL SERVICE On-Site Generation	291	46,036	74	3,939	0.1583
3	09P General Service	641,340	51,450,287	304	2,106,784	0.0802
4	09S General Service	3,503,259	317,072,332	40,703	86,069	0.0905
5	09T General Service	11,404	1,007,473	8	1,396,378	0.0883
6	15 DUSK TO DAWN LIGHT	1,291	825,302	0		0.6393
7	24S Irrigation & Pump	2,043,628	199,491,289	22,610	90,384	0.0976
8	24T Irrigation & Pump	0	0	0		
9	40 GENERAL SERVICE	13,853	1,420,434	1,358	10,203	0.1025
41	TOTAL Billed Small or Commercial	6,373,146	594,149,786	97,672	65,251	0.0932
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(7,130)	(5,864,919)			0.8226
43	TOTAL Small or Commercial	6,366,016	588,284,867	97,672	65,178	0.0924

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	19P Uniform Rate	2,374,449	175,017,350	138	17,154,356	0.0737
2	19S Uniform Rate	5,867	476,034	1	5,867,482	0.0811
3	19T Uniform Rate	120,172	9,163,839	4	33,536,440	0.0763
4	Special Contracts	1,275,459	87,713,013	6	206,831,189	0.0688
5	Other	0	(4,362,054)	0		
41	TOTAL Billed Large (or Ind.) Sales	3,775,947	268,008,182	149	25,313,614	0.071
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	2,259	2,588,589			1.1459
43	TOTAL Large (or Ind.)	3,778,206	270,596,771	149	25,328,758	0.0716

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	40 General Service	734	75,964	502	1,462	0.1035
2	41 Municipal Lighting (A, B, C)	21,299	4,180,050	3,830	5,561	0.1963
3	42 Signal Lighting	3,179	258,574	897	3,546	0.0813
4	Other	0	417	0		
41	TOTAL Billed Public Street and Highway Lighting	25,213	4,515,005	5,229	4,822	0.1791
42	TOTAL Unbilled Rev. (See Instr. 6)	34	1,899			0.0552
43	TOTAL	25,247	4,516,904	5,229	4,829	0.1789

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						

28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		15,119,961			

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	16,213,176	1,581,980,389	657,295	25,394,583	0.4618
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(33,418)	(10,438,715)	0		2.2744
43	TOTAL - All Accounts	16,179,758	1,571,541,674	657,261	25,409,610	0.4607

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
2. Enter the name of the purchaser in column (a). Do 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 setter can unilaterally get out of the contract.

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	3PR Trading Inc	SF	WSPP			
2	ADM Investor Services, Inc.	OS	WSPP			
3	Altop Energy Trading LLC	OS	OATT			
4	Altop Energy Trading LLC	SF	WSPP			
5	AmpRenew Offtake 1 LLC	OS	OATT			

6	AVANGRID POWER, LLC	SF	WSPP			
7	Avangrid Renewables, LLC	(d) OS	OATT			
8	Avista Corp.	SF	WSPP			
9	Avista Corp. - WWP Div.	(e) OS	OATT			
10	Black Hills Power Inc.	SF	WSPP			
11	Bonneville Power	(f) OS	OATT			
12	Bonneville Power Administration	SF	WSPP			
13	BP Energy Company	(g) OS	OATT			
14	BP Energy Company	SF	WSPP			
15	Brookfield Renewable Trading and Marketing LP	SF	WSPP			
16	California Independent System Operator	(h) SF	CAISO			
17	Calpine Energy Solutions, LLC	SF	WSPP			
18	Citigroup Energy Inc.	SF	ISDA			
19	City of Glendale	SF	WSPP			
20	Clatskanie PUD	SF	WSPP			
21	ConocoPhillips Company	SF	WSPP			
22	Constellation Energy Generation, LLC	SF	WSPP			
23	CP Energy Marketing (US) Inc.	SF	WSPP			
24	CP Energy Marketing Inc	(i) OS	OATT			
25	Dynasty Power Inc.	(j) OS	OATT			
26	Dynasty Power Inc.	SF	WSPP			
27	EDF Trading North America	(k) OS	OATT			
28	EDF Trading North America, LLC	SF	WSPP			
29	Energy Keepers, Inc	SF	WSPP			
30	Energy Keepers, Inc.	(l) OS	OATT			
31	Eugene Water & Electric Board	SF	WSPP			
32	Guzman Energy Group LLC	(m) OS	OATT			
33	Guzman Energy LLC	SF	WSPP			
34	Macquarie Energy LLC	(n) OS	OATT			
35	Macquarie Energy LLC	SF	WSPP			
36	MAG Energy Solutions	(o) OS	OATT			
37	MAG Energy Solutions Inc.	SF	WSPP			
38	Mercuria Energy America, LLC	(p) OS	OATT			
39	Mercuria Energy America, LLC	SF	WSPP			
40	MFT Energy US Power LLC	(q) OS	OATT			

41	Morgan Stanley Capital Group Inc.	⁽ⁱ⁾ OS	OATT			
42	Morgan Stanley Capital Group Inc.	SF	ISDA			
43	Nevada Power	^(s) OS	OATT			
44	Nevada Power Company, dba NV Energy	SF	WSPP			
45	NorthWestern Energy	⁽ⁱ⁾ OS	OATT			
46	NorthWestern Energy	SF	WSPP			
47	PacifiCorp	SF	WSPP			
48	PacifiCorp	^(u) OS	T-7			
49	PacifiCorp Inc.	^(v) OS	OATT			
50	Phillips 66 Energy Trading LLC	SF	WSPP			
51	Phillips 66 Energy Trading LLC	^(w) OS	OATT			
52	Portland General Electric Company	^(x) OS	OATT			
53	Portland General Electric Company	SF	WSPP			
54	Powerex Corp.	^(y) OS	OATT			
55	Powerex Corp.	SF	WSPP			
56	Puget Sound Energy	^(z) OS	OATT			
57	Puget Sound Energy, Inc.	SF	WSPP			
58	Rainbow Energy Marketing Corporation	^(aa) OS	OATT			
59	Rainbow Energy Marketing Corporation	SF	WSPP			
60	Riley Solar I	^(ab) OS	OATT			
61	Salt River Project	SF	WSPP			
62	Seattle City Light	^(ac) OS	OATT			
63	Seattle City Light	SF	WSPP			
64	Shell Energy North America (US), L.P.	^(ad) OS	OATT			
65	Shell Energy North America (US), L.P.	SF	WSPP			
66	Snohomish County PUD	SF	WSPP			
67	Starvation Solar I, LLC	^(ae) OS	OATT			
68	Suntex Solar, LLC	^(af) OS	OATT			
69	Tacoma Power	SF	WSPP			
70	TEC Energy Inc.	^(ag) OS	OATT			
71	Tenaska Power Services Co.	^(ah) OS	OATT			
72	Tenaska Power Services Co.	SF	WSPP			
73	The Energy Authority, Inc.	^(ai) OS	OATT			
74	The Energy Authority, Inc.	SF	WSPP			

75	TransAlta Energy Marketing (U.S.) Inc.	(aj) OS	OATT			
76	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP			
77	Transmission Penalty Distribution	(ak) OS	-			
78	Utah Associated Municipal Power Systems	(aj) OS	OATT			
79	Utah Associated Municipal Power Systems	SF	WSPP			
80	Vitol Inc.	(am) OS	OATT			
81	Vitol Inc.	SF	WSPP			
82	West Hines Solar, LLC	(ap) OS	OATT			
83	West Point RNG, LLC	(ap) OS	OATT			
84	Western Area Power Administration (WACM)	(ap) AD	T-7			
15	Subtotal - RQ					
16	Subtotal-Non-RQ					
17	Total					

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 setter can unilaterally get out of the contract.

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Megawatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)
			Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)	
1	3PR Trading Inc	184,350	0	6,443,060	0	6,443,060
2	ADM Investor Services, Inc.	0	0	0	558,628	558,628
3	Altop Energy Trading LLC	0	0	0	17,534	17,534
4	Altop Energy Trading LLC	97,458	0	2,894,116	0	2,894,116
5	AmpRenew Offtake 1 LLC	0	0	0	10,723	10,723
6	AVANGRID POWER, LLC	5,797	0	240,516	0	240,516
7	Avangrid Renewables, LLC	0	0	0	14,953	14,953
8	Avista Corp.	20,761	0	1,035,206	0	1,035,206
9	Avista Corp. - WWP Div.	0	0	0	704	704

10	Black Hills Power Inc.	2,493	0	53,939	0	53,939
11	Bonneville Power	0	0	0	3,430,490	3,430,490
12	Bonneville Power Administration	145,554	0	5,412,064	0	5,412,064
13	BP Energy Company	0	0	0	551	551
14	BP Energy Company	75,166	0	2,635,139	0	2,635,139
15	Brookfield Renewable Trading and Marketing LP	16	0	720	0	720
16	California Independent System Operator	317,660	0	26,629,227	0	26,629,227
17	Calpine Energy Solutions, LLC	100,150	0	3,720,795	0	3,720,795
18	Citigroup Energy Inc.	80	0	6,000	0	6,000
19	City of Glendale	47,375	0	3,065,113	0	3,065,113
20	Clatskanie PUD	1,028	0	37,434	0	37,434
21	ConocoPhillips Company	223	0	8,410	0	8,410
22	Constellation Energy Generation, LLC	202,149	0	7,201,172	0	7,201,172
23	CP Energy Marketing (US) Inc.	86	0	3,126	0	3,126
24	CP Energy Marketing Inc	0	0	0	174	174
25	Dynasty Power Inc.	0	0	0	98,931	98,931
26	Dynasty Power Inc.	489,559	0	15,467,464	0	15,467,464
27	EDF Trading North America	0	0	0	60	60
28	EDF Trading North America, LLC	75	0	750	0	750
29	Energy Keepers, Inc	50	0	2,451	0	2,451
30	Energy Keepers, Inc.	0	0	0	217,141	217,141
31	Eugene Water & Electric Board	6,318	0	221,129	0	221,129
32	Guzman Energy Group LLC	0	0	0	16,812	16,812
33	Guzman Energy LLC	583	0	29,610	0	29,610
34	Macquarie Energy LLC	0	0	0	57,194	57,194
35	Macquarie Energy LLC	32,133	0	1,440,580	0	1,440,580
36	MAG Energy Solutions	0	0	0	17,445	17,445
37	MAG Energy Solutions Inc.	3	0	77	0	77
38	Mercuria Energy America, LLC	0	0	0	95,806	95,806
39	Mercuria Energy America, LLC	150,604	0	5,574,773	0	5,574,773
40	MFT Energy US Power LLC	0	0	0	2,850	2,850
41	Morgan Stanley Capital Group Inc.	0	0	0	272,570	272,570
42	Morgan Stanley Capital Group Inc.	1,636	0	30,413	0	30,413
43	Nevada Power	0	0	0	2,974	2,974
44	Nevada Power Company, dba NV Energy	1,265	0	79,725	0	79,725
45	NorthWestern Energy	0	0	0	4,627	4,627
46	NorthWestern Energy	4,097	0	102,202	0	102,202

47	PacifiCorp	131,500	0	2,262,040	0	2,262,040
48	PacifiCorp	80	0	0	3,339	3,339
49	PacifiCorp Inc.	0	0	0	4,008,390	4,008,390
50	Phillips 66 Energy Trading LLC	151,339	0	3,355,028	0	3,355,028
51	Phillips 66 Energy Trading LLC	0	0	0	617,608	617,608
52	Portland General Electric Company	0	0	0	4,818	4,818
53	Portland General Electric Company	12,546	0	403,826	0	403,826
54	Powerex Corp.	0	0	0	336,635	336,635
55	Powerex Corp.	89,724	0	2,033,060	0	2,033,060
56	Puget Sound Energy	0	0	0	1,639	1,639
57	Puget Sound Energy, Inc.	3,041	0	108,878	0	108,878
58	Rainbow Energy Marketing Corporation	0	0	0	30,703	30,703
59	Rainbow Energy Marketing Corporation	120,464	0	2,619,637	0	2,619,637
60	Riley Solar I	0	0	0	369	369
61	Salt River Project	72	0	3,384	0	3,384
62	Seattle City Light	0	0	0	330,961	330,961
63	Seattle City Light	28,180	0	1,675,876	0	1,675,876
64	Shell Energy North America (US), L.P.	0	0	0	24,860	24,860
65	Shell Energy North America (US), L.P.	129,766	0	4,711,237	0	4,711,237
66	Snohomish County PUD	749	0	31,465	0	31,465
67	Starvation Solar I, LLC	0	0	0	818	818
68	Suntex Solar, LLC	0	0	0	185	185
69	Tacoma Power	90	0	3,030	0	3,030
70	TEC Energy Inc.	0	0	0	70	70
71	Tenaska Power Services Co.	0	0	0	7,650	7,650
72	Tenaska Power Services Co.	31	0	620	0	620
73	The Energy Authority, Inc.	0	0	0	89,862	89,862
74	The Energy Authority, Inc.	15,468	0	518,840	0	518,840
75	TransAlta Energy Marketing (U.S.) Inc.	0	0	0	56,122	56,122
76	TransAlta Energy Marketing (U.S.) Inc.	43,725	0	1,964,435	0	1,964,435
77	Transmission Penalty Distribution	0	0	0	2,964	2,964
78	Utah Associated Municipal Power Systems	0	0	0	15,433	15,433
79	Utah Associated Municipal Power Systems	6,180	0	153,700	0	153,700
80	Vitol Inc.	0	0	0	13	13
81	Vitol Inc.	276,925	0	11,980,682	0	11,980,682

82	West Hines Solar, LLC	0	0	0	755	755
83	West Point RNG, LLC	0	0	0	20,355	20,355
84	Western Area Power Administration (WACM)	0	0	0	4,815	4,815
15	Subtotal - RQ	0				
16	Subtotal-Non-RQ	2,896,549	0	114,160,948	10,378,531	124,539,480
17	Total	2,896,549	0	114,160,948	10,378,531	124,539,480

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode
ADM Investor Services, Inc Futures Account Document, dated May 6, 2015
(b) Concept: StatisticalClassificationCode
Financial Transmission Losses
(c) Concept: StatisticalClassificationCode
Financial Transmission Losses
(d) Concept: StatisticalClassificationCode
Financial Transmission Losses
(e) Concept: StatisticalClassificationCode
Financial Transmission Losses
(f) Concept: StatisticalClassificationCode
Financial Transmission Losses
(g) Concept: StatisticalClassificationCode
Financial Transmission Losses
(h) Concept: StatisticalClassificationCode
Includes actual billing and estimate accrual
(i) Concept: StatisticalClassificationCode
Financial Transmission Losses
(j) Concept: StatisticalClassificationCode
Financial Transmission Losses
(k) Concept: StatisticalClassificationCode
Financial Transmission Losses
(l) Concept: StatisticalClassificationCode
Financial Transmission Losses
(m) Concept: StatisticalClassificationCode
Financial Transmission Losses
(n) Concept: StatisticalClassificationCode
Financial Transmission Losses
(o) Concept: StatisticalClassificationCode
Financial Transmission Losses
(p) Concept: StatisticalClassificationCode
Financial Transmission Losses
(q) Concept: StatisticalClassificationCode
Financial Transmission Losses
(r) Concept: StatisticalClassificationCode
Financial Transmission Losses

(s) Concept: StatisticalClassificationCode
Financial Transmission Losses
(t) Concept: StatisticalClassificationCode
Financial Transmission Losses
(u) Concept: StatisticalClassificationCode
Spinning or Operating Reserves
(v) Concept: StatisticalClassificationCode
Financial Transmission Losses
(w) Concept: StatisticalClassificationCode
Financial Transmission Losses
(x) Concept: StatisticalClassificationCode
Financial Transmission Losses
(y) Concept: StatisticalClassificationCode
Financial Transmission Losses
(z) Concept: StatisticalClassificationCode
Financial Transmission Losses
(aa) Concept: StatisticalClassificationCode
Financial Transmission Losses
(ab) Concept: StatisticalClassificationCode
Financial Transmission Losses
(ac) Concept: StatisticalClassificationCode
Financial Transmission Losses
(ad) Concept: StatisticalClassificationCode
Financial Transmission Losses
(ae) Concept: StatisticalClassificationCode
Financial Transmission Losses
(af) Concept: StatisticalClassificationCode
Financial Transmission Losses
(ag) Concept: StatisticalClassificationCode
Financial Transmission Losses
(ah) Concept: StatisticalClassificationCode
Financial Transmission Losses
(ai) Concept: StatisticalClassificationCode
Financial Transmission Losses
(aj) Concept: StatisticalClassificationCode
Financial Transmission Losses
(ak) Concept: StatisticalClassificationCode
Transmission penalty distribution credits
(al) Concept: StatisticalClassificationCode
Financial Transmission Losses

[\(am\)](#) Concept: StatisticalClassificationCode

Financial Transmission Losses

[\(an\)](#) Concept: StatisticalClassificationCode

Financial Transmission Losses

[\(ao\)](#) Concept: StatisticalClassificationCode

Financial Transmission Losses

[\(ap\)](#) Concept: StatisticalClassificationCode

2023 Reserves Rate True Up

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,853,978	954,516
5	(501) Fuel	115,924,068	97,426,834
6	(502) Steam Expenses	6,096,485	8,856,796
7	(503) Steam from Other Sources	0	0
8	(Less) (504) Steam Transferred-Cr.	0	0
9	(505) Electric Expenses	824,172	1,752,549
10	(506) Miscellaneous Steam Power Expenses	7,809,520	8,027,360
11	(507) Rents	202,361	223,832
12	(509) Allowances	0	0
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	132,710,584	117,241,887
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	176,252	52,861
16	(511) Maintenance of Structures	255,697	355,731
17	(512) Maintenance of Boiler Plant	8,092,640	8,521,483
18	(513) Maintenance of Electric Plant	2,568,217	3,152,576
18.1	(513.1) Maintenance of Computer Hardware	778,549	
18.2	(513.2) Maintenance of Computer Software	68,171	
18.3	(513.3) Maintenance of Communication Equipment	7,575	
19	(514) Maintenance of Miscellaneous Steam Plant	9,562,449	7,462,549
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	21,509,550	19,545,200
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	154,220,134	136,787,087
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	0	0
25	(518) Fuel	0	0
26	(519) Coolants and Water	0	0
27	(520) Steam Expenses	0	0
28	(521) Steam from Other Sources	0	0
29	(Less) (522) Steam Transferred-Cr.	0	0

30	(523) Electric Expenses	0	0
31	(524) Miscellaneous Nuclear Power Expenses	0	0
32	(525) Rents	0	0
33	TOTAL Operation (Enter Total of lines 24 thru 32)	0	0
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	0	0
36	(529) Maintenance of Structures	0	0
37	(530) Maintenance of Reactor Plant Equipment	0	0
38	(531) Maintenance of Electric Plant	0	0
38.1	(531.1) Maintenance of Computer Hardware	0	
38.2	(531.2) Maintenance of Computer Software	0	
38.3	(531.3) Maintenance of Communication Equipment	0	
39	(532) Maintenance of Miscellaneous Nuclear Plant	0	0
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	0	0
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	0	0
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	5,672,899	6,209,394
45	(536) Water for Power	3,461,593	2,910,129
46	(537) Hydraulic Expenses	21,459,432	21,238,903
47	(538) Electric Expenses	2,233,869	2,316,268
48	(539) Miscellaneous Hydraulic Power Generation Expenses	6,331,359	6,579,401
49	(540) Rents	322,728	319,089
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	39,481,880	39,573,184
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	3,951	179,739
54	(542) Maintenance of Structures	1,127,335	1,151,714
55	(543) Maintenance of Reservoirs, Dams, and Waterways	687,322	1,721,351
56	(544) Maintenance of Electric Plant	3,202,905	3,786,618
56.1	(544.1) Maintenance of Computer Hardware	85,447	
56.2	(544.2) Maintenance of Computer Software	836,211	
56.3	(544.3) Maintenance of Communication Equipment	28,907	
57	(545) Maintenance of Miscellaneous Hydraulic Plant	5,760,124	5,139,109
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	11,732,202	11,978,531
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	51,214,082	51,551,715
60	D. Other Power Generation		
61	Operation		

62	(546) Operation Supervision and Engineering	543,261	596,233
63	(547) Fuel	137,312,521	161,776,803
64	(548) Generation Expenses	5,637,863	6,247,380
65	(549) Miscellaneous Other Power Generation Expenses	475,153	729,077
66	(550) Rents	0	0
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	143,968,798	169,349,493
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	144,765	0
70	(552) Maintenance of Structures	161,698	101,732
71	(553) Maintenance of Generating and Electric Plant	251,467	109,760
71.1	(553.1) Maintenance of Computer Hardware	0	
71.2	(553.2) Maintenance of Computer Software	375,494	
71.3	(553.3) Maintenance of Communication Equipment	1,135	
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	4,080,830	3,223,775
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	5,015,389	3,435,267
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	148,984,187	172,784,760
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	380,182,702	411,969,444
76.1	(555.1) Power Purchased for Storage Operations	0	
76.2	(555.2) Bundled Environmental Credits	0	
76.3	(555.3) Unbundled Environmental Credits	1,024,786	
77	(556) System Control and Load Dispatching	0	84
78	(557) Other Expenses	16,996,481	82,803,893
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	398,203,969	494,773,421
79.1	F. Solar Generation		
79.2	Operation		
79.3	(558.1) Operation Supervision and Engineering	0	
79.4	(558.2) Solar Panel Generation and Other Plant Operating Expenses	0	
79.6	(558.4) Rents	0	
79.7	TOTAL Operation (Enter Total of lines 79.3 thru 79.6)	0	
79.8	Maintenance		
79.9	(558.6) Maintenance Supervision and Engineering	0	
79.10	(558.7) Maintenance of Solar Panels, Structures, and Equipment	0	
79.11	(558.8) Maintenance of Computer Hardware	0	
79.12	(558.9) Maintenance of Computer Software	0	
79.13	(558.10) Maintenance of Communication Equipment	0	

79.14	(558.11) Maintenance of Miscellaneous Solar Generation Plant	0	
79.15	TOTAL Maintenance (Enter Total of lines 79.9 thru 79.14)	0	
79.16	TOTAL Power Production Expenses-Solar (total of lines 79.7 & 79.15)	0	
79.17	G. Wind Generation		
79.18	Operation		
79.19	(558.13) Operation Supervision and Engineering	0	
79.20	(558.14) Wind Turbine Generation and Other Plant Operating Expenses	0	
79.21	(558.16) Rents	0	
79.22	TOTAL Operation (Enter Total of lines 79.19 thru 79.21)	0	
79.23	Maintenance		
79.24	(558.18) Maintenance Supervision and Engineering	0	
79.25	(558.19) Maintenance of Wind Turbines, Structures, and Equipment	0	
79.26	(558.20) Maintenance of Computer Hardware	0	
79.27	(558.21) Maintenance of Computer Software	0	
79.28	(558.22) Maintenance of Communication Equipment	0	
79.29	(558.23) Maintenance of Miscellaneous Wind Generation Plant	0	
79.30	TOTAL Maintenance (Enter Total of lines 79.24 thru 79.29)	0	
79.31	TOTAL Power Production Expenses-Wind (total of lines 79.22 & 79.30)	0	
79.32	H. Other Renewable Generation		
79.33	Operation		
79.34	(559.1) Operation Supervision and Engineering	0	
79.35	(559.2) Other Miscellaneous Generation and Other Plant Operating Expenses	0	
79.36	(559.3) Fuel	0	
79.37	(559.4) Rents	0	
79.38	TOTAL Operation (Enter Total of lines 79.34 thru 79.37)	0	
79.39	Maintenance		
79.40	(559.6) Maintenance Supervision and Engineering	0	
79.41	(559.7) Maintenance of Structures	0	
79.42	(559.9) Maintenance of Boilers	0	
79.43	(559.10) Maintenance of Generating and Electric Equipment	0	
79.44	(559.12) Maintenance of Computer Hardware	0	
79.45	(559.13) Maintenance of Computer Software	0	
79.46	(559.14) Maintenance of Communication Equipment	0	
79.47	(559.15) Maintenance of Miscellaneous Renewable Production Plant	0	
79.48	TOTAL Maintenance (Enter Total of lines 79.40 thru 79.47)	0	

79.49	TOTAL Power Production Expenses-Other Renewable (total of lines 79.38 & 79.48)	0	
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74, 79, 79.16, 79.31, & 79.49)	752,622,372	855,896,983
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,244,220	2,806,087
85	(561.1) Load Dispatch-Reliability	0	16,367
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,739,932	2,976,230
87	(561.3) Load Dispatch-Transmission Service and Scheduling	444,049	426,509
88	(561.4) Scheduling, System Control and Dispatch Services	15,284	14,967
89	(561.5) Reliability, Planning and Standards Development	0	0
90	(561.6) Transmission Service Studies	4,307	907
91	(561.7) Generation Interconnection Studies	305,906	255,963
92	(561.8) Reliability, Planning and Standards Development Services	1,773,326	1,406,907
93	(562) Station Expenses	1,646,085	2,589,638
94	(563) Overhead Lines Expenses	1,181,001	1,249,690
95	(564) Underground Lines Expenses	0	0
96	(565) Transmission of Electricity by Others	11,254,079	13,112,150
97	(566) Miscellaneous Transmission Expenses	0	0
98	(567) Rents	4,602,313	4,528,250
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	25,210,502	29,383,665
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	130,252	470,610
102	(569) Maintenance of Structures	48,722	11,359
103	(569.1) Maintenance of Computer Hardware	4,635	27,362
104	(569.2) Maintenance of Computer Software	1,680,781	1,642,560
105	(569.3) Maintenance of Communication Equipment	1,100,641	22,453
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	0	0
107	(570) Maintenance of Station Equipment	2,382,931	3,192,925
108	(571) Maintenance of Overhead Lines	2,636,462	4,186,984
109	(572) Maintenance of Underground Lines	0	0
110	(573) Maintenance of Miscellaneous Transmission Plant	1,976	760
111	TOTAL Maintenance (Total of Lines 101 thru 110)	7,986,400	9,555,013
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	33,196,902	38,938,678
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision	0	

116	(575.2) Day-Ahead and Real-Time Market Facilitation	0	
117	(575.3) Transmission Rights Market Facilitation	0	
118	(575.4) Capacity Market Facilitation	0	
119	(575.5) Ancillary Services Market Facilitation	0	
120	(575.6) Market Monitoring and Compliance	0	
121	(575.7) Market Facilitation, Monitoring and Compliance Services	655,908	552,732
122	(575.8) Rents	0	
123	Total Operation (Lines 115 thru 122)	655,908	552,732
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements	0	
126	(576.2) Maintenance of Computer Hardware	0	
127	(576.3) Maintenance of Computer Software	0	
128	(576.4) Maintenance of Communication Equipment	0	
129	(576.5) Maintenance of Miscellaneous Market Operation Plant	0	
130	Total Maintenance (Lines 125 thru 129)	0	
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	655,908	552,732
131.1	4. ENERGY STORAGE EXPENSES		
131.2	Operation		
131.3	(577.1) Operation Supervision and Engineering	5,801	
131.4	(577.2) Operation of Energy Storage Equipment	82	
131.5	(577.3) Storage Fuel	0	
131.6	(577.4) Rents	13,321,452	
131.7	Total Operation (Lines 131.3 thru 131.6)	13,327,335	
131.8	Maintenance		
131.9	(578.1) Maintenance Supervision and Engineering	552,889	
131.10	(578.2) Maintenance of Energy Storage Equipment and Structures	671,820	
131.11	(578.3) Maintenance of Computer Hardware	0	
131.12	(578.4) Maintenance of Computer Software	0	
131.13	(578.5) Maintenance of Communication Equipment	0	
131.14	(578.6) Maintenance of Miscellaneous Other Energy Storage Plant	0	
131.15	Total Maintenance (Lines 131.9 thru 131.14)	1,224,709	
131.16	TOTAL Energy Storage Expenses (Total of 131.7 and 131.15)	14,552,044	
132	5. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	4,541,786	4,981,783
135	(581) Load Dispatching	6,124,855	5,988,645
136	(582) Station Expenses	1,976,977	1,953,587

137	(583) Overhead Line Expenses	6,577,744	6,679,549
138	(584) Underground Line Expenses	6,965,515	6,009,462
139	(585) Street Lighting and Signal System Expenses	0	190
140	(586) Meter Expenses	6,808,739	6,857,272
141	(587) Customer Installations Expenses	1,192,523	1,261,551
142	(588) Miscellaneous Expenses	4,425,792	4,391,126
143	(589) Rents	544,032	403,629
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	39,157,963	38,526,794
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	5,363	9,118
147	(591) Maintenance of Structures	10,382	0
148	(592) Maintenance of Station Equipment	3,938,401	5,336,750
148.1	(592.2) Maintenance of Computer Hardware	47,779	
148.2	(592.3) Maintenance of Computer Software	2,681,112	
148.3	(592.4) Maintenance of Communication Equipment	455,777	
149	(593) Maintenance of Overhead Lines	37,075,600	35,534,246
150	(594) Maintenance of Underground Lines	578,159	987,659
151	(595) Maintenance of Line Transformers	68,104	59,807
152	(596) Maintenance of Street Lighting and Signal Systems	181,025	202,841
153	(597) Maintenance of Meters	1,110,722	1,017,258
154	(598) Maintenance of Miscellaneous Distribution Plant	263,233	220,009
155	TOTAL Maintenance (Total of Lines 146 thru 154)	46,415,657	43,367,688
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	85,573,620	81,894,482
157	6. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	932,868	917,633
160	(902) Meter Reading Expenses	1,719,608	2,086,175
161	(903) Customer Records and Collection Expenses	15,091,267	17,311,614
162	(904) Uncollectible Accounts	3,003,813	4,630,705
163	(905) Miscellaneous Customer Accounts Expenses	(59)	11
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	20,747,497	24,946,138
165	7. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	1,323,720	1,166,372
168	(908) Customer Assistance Expenses	40,454,717	37,555,632
169	(909) Informational and Instructional Expenses	258,949	342,954
170	(910) Miscellaneous Customer Service and Informational Expenses	757,751	733,643

171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	42,795,137	39,798,601
172	8. SALES EXPENSES		
173	Operation		
174	(911) Supervision	0	0
175	(912) Demonstrating and Selling Expenses	0	0
176	(913) Advertising Expenses	0	0
177	(916) Miscellaneous Sales Expenses	0	0
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	0	0
179	9. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	94,955,749	110,254,504
182	(921) Office Supplies and Expenses	9,273,019	19,328,502
183	(Less) (922) Administrative Expenses Transferred-Credit	40,658,997	47,555,951
184	(923) Outside Services Employed	8,054,542	10,696,562
185	(924) Property Insurance	5,056,382	5,047,711
186	(925) Injuries and Damages	11,331,882	10,612,690
187	(926) Employee Pensions and Benefits	77,313,069	84,097,252
188	(927) Franchise Requirements	0	0
189	(928) Regulatory Commission Expenses	7,850,939	6,953,560
190	(929) (Less) Duplicate Charges-Cr.	0	0
191	(930.1) General Advertising Expenses	190,738	133,442
192	(930.2) Miscellaneous General Expenses	4,978,975	4,681,625
193	(931) Rents	0	0
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	178,346,298	204,249,897
195	Maintenance		
196	(935) Maintenance of General Plant	4,359,977	7,588,454
196.1	(935.1) Maintenance of Computer Hardware	3,806,360	0
196.2	(935.2) Maintenance of Computer Software	33,256,650	0
196.3	(935.3) Maintenance of Communication Equipment	2,899,708	0
196.4	TOTAL Maintenance (Enter Total of lines 196 thru 196.3)	44,322,695	7,588,454
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196.4)	222,668,993	211,838,351
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 131.16, 156, 164, 171, 178, and 197)	1,172,812,473	1,253,865,965

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

PURCHASED POWER (Account 555)

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

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

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

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

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

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

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

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

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a 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)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	
1	AJMS - Little Wood River Ranch II	LU					3,067
2	Arkoosh Hydro - Little Wood River Ranch 1	LU					3,376

3	American Falls Solar, LLC	LU				43,268
4	American Falls Solar II, LLC	LU				45,466
5	Baker City Hydro	LU				628
6	Bannock County Landfill	LU				12,754
7	Barber Dam Hydro	LU				6,669
8	Bennett Creek Wind Farm	LU				36,929
9	Benson Creek Windfarm	LU				26,324
10	Birch Creek	LU				345
11	Black Canyon Bliss Hydro	LU				113
12	Blind Canyon	LU				3,666
13	Burley Butte Wind Park	LU				54,140
14	Camp Reed Wind Park	LU				59,978
15	Carroll Family Enterprises/Malad River	LU				1,278
16	Cassia Wind Farm LLC	LU				17,815
17	CCP OR Tenant 1, LLC					0
18	Grove Solar Center, LLC	LU				13,204
19	Hyline Solar Center, LLC	LU				19,914
20	Open Range Solar Center, LLC	LU				22,169
21	Railroad Solar Center, LLC	LU				10,168
22	Thunderegg Solar Center, LLC	LU				20,272
23	Vale Air Solar Center, LLC	LU				20,635
24	City of Hailey	LU				55
25	City of Pocatello	LU				729
26	Clear Springs Trout	LU				1,091
27	Cold Springs Windfarm	LU				46,182
28	Coleman Hydro	LU				173
29	College of Southern Idaho - Pristine Springs #1	LU				788
30	College of Southern Idaho - Pristine Springs #3	LU				1,599
31	Crystal Springs	LU				8,483
32	Curry Cattle Company	LU				433
33	Cycle Horseshoe Bend Wind	LU				17,341
34	Desert Meadow Windfarm	LU				53,766
35	Durbin Creek Windfarm	LU				25,935
36	Durkee Solar	LU				0
37	Eightmile Hydro Project	LU				1,081
38	Enerparc Solar Development LLC					0
39	Baker Solar Center	LU				32,529
40	Brush Solar	LU				6,363

41	Morgan Solar	LU					7,055
42	Ontario Solar Center	LU					7,154
43	Vale I Solar	LU					5,958
44	Faulkner Ranch Hydro	LU					3,068
45	Fossil Gulch Wind	LU					20,643
46	Hidden Hollow Landfill Gas	LU					2,740
47	Golden Valley Wind Park	LU					28,932
48	Grand View PV Solar Two	LU					185,695
49	Hammett Hill Windfarm	LU					52,591
50	Hazelton Wilson Joint Venture	^(a) LU					0
51	Hazelton B	LU					23,049
52	Wilson Lake Hydro	LU					26,968
53	High Mesa Wind Project	LU					76,368
54	H.K. Hydro Mud Creek S & S	LU					1,544
55	Horseshoe Bend Hydro	LU					46,815
56	Hot Springs Wind Farm	LU					33,052
57	Hydroland						0
58	Elk Creek Hydro	LU					3,192
59	Rock Creek II	LU					4,978
60	ID Solar 1	LU					91,991
61	Idaho Winds LLC - Sawtooth Wind Project	LU					49,737
62	J R Simplot Co.	LU					66,125
63	J.M. Miller/Sahko Hydro	LU					988
64	Jett Creek Windfarm	LU					24,791
65	Kootenai Energy - Fighting Creek	LU					17,367
66	Koosh Inc. Geo Bon #2	LU					3,227
67	Koyle Small Hydro	LU					3,366
68	Lateral #10	LU					4,557
69	Lemhi Hydro	LU					928
70	Lemoyne Power Plant	LU					653
71	Lime Wind Energy	LU					5,411
72	Little Mac Power Co.- Cedar Draw	LU					4,274
73	Little Wood River Irrigation District	LU					2,844
74	Low Line Midway Hydro	LU					7,489
75	Lower Low Line - Lowline #2	LU					8,373
76	Mainline Windfarm	LU					51,772
77	Marco Ranches	LU					2,475

78	Marysville Hydro Partners- Fall River	LU				43,350
79	McCollum Enterprises -Canyon Springs	LU				576
80	MC6 Hydro	LU				8,379
81	Milner Dam Wind	LU				50,520
82	Mt. Home Solar 1, LLC	LU				48,243
83	Mud Creek White Hydro, Inc	LU				339
84	Murphy Flat Power, LLC	LU				40,951
85	North Gooding Main Hydro	LU				4,572
86	North Side Energy Company Inc					0
87	Bypass	LU				28,276
88	Hazelton A	LU				24,869
89	Head of U Canal Project	LU				4,605
90	Orchard Ranch Solar, LLC	LU				45,754
91	Oregon Trail Wind Park	LU				34,931
92	Owyhee Irrigation District					0
93	Mitchell Butte	LU				6,602
94	Owyhee Dam Csp	LU				28,347
95	Tunnel #1	LU				21,160
96	Payne's Ferry Wind Park	LU				57,977
97	Pico Energy, LLC	LU				11,101
98	Pigeon Cove	LU				7,840
99	Pilgrim Stage Station Wind Park	LU				30,712
100	Prospector Windfarm	LU				23,518
101	Reynolds Irrigation	LU				1,007
102	Richard Kaster					0
103	Box Canyon	LU				2,000
104	Briggs Creek	LU				3,334
105	Riverside Hydro - Mora Drop	LU				4,602
106	Riverside Investments					0
107	Arena Drop	LU				1,613
108	Fargo Drop Hydroelectric	LU				3,758
109	Rockland Wind Farm	LU				219,377
110	Ryegrass Windfarm	LU				48,227
111	Salmon Falls Wind	LU				58,266
112	Shingle Creek	LU				916
113	Shorock Hydro Inc.					0
114	Rock Creek #1	LU				10,016
115	Shoshone Hydro	LU				1,393
116	Shoshone #2	LU				2,335

117	Simcoe Solar, LLC	LU				48,890
118	Snake River Pottery	LU				415
119	Snedigar Ranch Hydro	LU				1,224
120	South Forks Joint Venture- Lowline Canal	^(f) LU				26,126
121	Southern Idaho Regional Solid Waste - SISW LFGE	LU				27,287
122	Spring Water Farms/Fisheries Dev.	LU				533
123	Tamarack Energy Partnership	LU				14,096
124	Tasco - Nampa	^(g) OS				1
125	Thousand Springs Wind Park	LU				28,641
126	Tuana Gulch Wind Park	LU				27,415
127	Tuana Springs Expansion	LU				63,610
128	Two Ponds Windfarm	LU				55,098
129	Von Alan Industries - Trout Co	LU				606
130	White Water Ranch	LU				736
131	Willow Spring Windfarm	LU				30,526
132	Wood Hydro					0
133	Black Canyon #3	LU				285
134	Dietrich Drop	LU				11,886
135	Jim Knight	LU				1,363
136	Magic Reservoir Hydro	LU				9,819
137	Mile 28	LU				4,985
138	Sagebrush Hydro Project	LU				1,410
139	Yahoo Creek Wind Park	LU				58,793
140	Scheduling Deviation	^(e) OS				20,650
141	3PR Trading Inc	SF	WSPP			136
142	ADM Investor Services, Inc.	^(f) OS	WSPP			0
143	AlbertaEX, L.P.	^(g) OS	WSPP			30
144	Altop Energy Trading LLC	SF	WSPP			29,394
145	Arizona Public Service Co.	SF	WSPP			5,400
146	AVANGRID POWER, LLC	SF	WSPP			78,725
147	AVANGRID RENEWABLES, LLC	^(h) OS	WSPP			5
148	Avista Corp.	⁽ⁱ⁾ OS	WSPP			28
149	Avista Corp.	^(j) OS	WSPP			0
150	Avista Corp.	SF	WSPP			9,089
151	Black Mesa Energy, LLC	LU	-			84,647
152	Bonneville Power Administration	^(k) OS	WSPP			132

153	Bonneville Power Administration	^(b) OS	WSPP				0
154	Bonneville Power Administration	SF	WSPP				15,010
155	BP Energy Company	SF	WSPP				1,886
156	Brookfield Renewable Trading and Marketing LP	SF	WSPP				4,400
157	California Independent System Operator	SF	CAISO				320,140
158	Calpine Energy Solutions, LLC	SF	WSPP				322
159	Chelan Co PUD	^(m) OS	WSPP				2
160	Chelan Co PUD	SF	WSPP				800
161	Citadel Energy Marketing LLC	SF	WSPP				800
162	Citigroup Energy Inc.	SF	ISDA				23,575
163	City of Glendale	SF	WSPP				86
164	Clatskanie PUD	SF	WSPP				411
165	ConocoPhillips Company	SF	WSPP				14,700
166	Constellation Energy Generation, LLC	SF	WSPP				150
167	CP Energy Marketing (US) Inc.	SF	WSPP				151,925
168	Douglas County PUD	⁽ⁿ⁾ OS	WSPP				1
169	Dynasty Power Inc.	SF	WSPP				50,990
170	EDF Trading North America, LLC	SF	WSPP				10,000
171	Energy Keepers, Inc	SF	WSPP				7,616
172	Franklin Solar LLC	LU					240,371
173	Grant CO Public Utility District #2 -- Electric System	^(o) OS	WSPP				6
174	Gridforce Energy Management, LLC	^(p) OS	WSPP				3
175	J.Aron & Company LLC	SF	WSPP				10,000
176	Jackpot Holdings, LLC	LU	-				270,421
177	Macquarie Energy LLC	SF	WSPP				94,000
178	MAG Energy Solutions Inc.	SF	WSPP				32,350
179	Mercuria Energy America, LLC	SF	WSPP				99,968
180	Merrill Lynch Commodities, Inc.	^(q) OS	ISDA				0
181	Morgan Stanley Capital Group Inc.	SF	ISDA				1,800
182	Neal Hot Springs Unit #1	LU	-				152,270
183	Nevada Power Company, dba NV Energy	SF	WSPP				775
184	NorthWestern Energy	^(r) OS	WSPP				22
185	NorthWestern Energy	^(s) OS	WSPP				0
186	NorthWestern Energy	SF	WSPP				0
187	Oregon Solar Customers	^(t) OS	-				705

188	PacifiCorp	(u) OS	WSPP				140
189	PacifiCorp Inc.	(u) OS	WSPP				0
190	Phillips 66 Energy Trading LLC	SF	WSPP				530,846
191	Pleasant Valley Solar LLC	LU					509,525
192	Portland General Electric Company	(u) OS	WSPP				44
193	Portland General Electric Company	SF	WSPP				82,883
194	Powerex Corp.	SF	WSPP				12,690
195	Puget Sound Energy, Inc.	(u) OS	WSPP				44
196	Puget Sound Energy, Inc.	SF	WSPP				6,600
197	Raft River Energy I LLC	LU	-				88,140
198	Rainbow Energy Marketing Corporation	SF	WSPP				953
199	Salt River Project	SF	WSPP				96,650
200	Seattle City Light	(u) OS	WSPP				14
201	Seattle City Light	SF	WSPP				4,540
202	Shell Energy North America (US), L.P.	SF	WSPP				512,803
203	Sierra Pacific Power Co., dba NV Energy	(u) OS	WSPP				0
204	Sierra Pacific Power Co., dba NV Energy	SF	WSPP				0
205	Snohomish County PUD	SF	WSPP				575
206	Tacoma Power	(au) OS	WSPP				4
207	Tacoma Power	SF	WSPP				230
208	Telocaset Wind Power Partners LLC	LU	APP-A				306,412
209	Tenaska Power Services Co.	SF	WSPP				4,800
210	Tenaska Power Services Co.	(au) AD	WSPP				0
211	The Energy Authority, Inc.	SF	WSPP				10,944
212	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP				84,564
213	Vitol Inc.	SF	WSPP				991
214	PacifiCorp Inc.	(ac) EX	-				
215	Clatskanie PUD	EX	153				
216	POWIN LLC	(ad) OS					0
217	Jackalope Wind, LLC	(au) OS					0
218	Franklin Battery Storage, LLC	(ad) OS					0
219	Acctg Valuation of Clatskanie PUD	(au) EX					0
220	Demand Response Avoided Energy	(ah) OS					0

221	CEYW Excess Generation	(a) OS					0
222	On-Site Generation - Exports	(a) OS					0
223	Oregon Community Solar	(a) OS					6,830
224	ADM Investor Services, Inc.	(a) OS					0
225	Dynasty Power Inc.	(a) OS					0
15	TOTAL						6,783,070

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)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER		
			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)
1	AJMS - Little Wood River Ranch II					183,255	0
2	Arkoosh Hydro - Little Wood River Ranch 1					291,394	0
3	American Falls Solar, LLC					3,075,027	0
4	American Falls Solar II, LLC					3,085,178	0
5	Baker City Hydro					49,298	0
6	Bannock County Landfill					1,030,550	0

7	Barber Dam Hydro					397,325	0
8	Bennett Creek Wind Farm					2,864,812	0
9	Benson Creek Windfarm					2,055,824	0
10	Birch Creek					22,974	0
11	Black Canyon Bliss Hydro					5,748	0
12	Blind Canyon					255,035	0
13	Burley Butte Wind Park					3,841,622	0
14	Camp Reed Wind Park					4,987,544	0
15	Carroll Family Enterprises/Malad River					88,268	0
16	Cassia Wind Farm LLC					1,136,323	0
17	CCP OR Tenant 1, LLC					0	0
18	Grove Solar Center, LLC					1,125,505	0
19	Hyline Solar Center, LLC					1,690,201	0
20	Open Range Solar Center, LLC					1,881,117	0
21	Railroad Solar Center, LLC					862,306	0
22	Thunderegg Solar Center, LLC					1,735,391	0
23	Vale Air Solar Center, LLC					1,751,427	0
24	City of Hailey					2,253	0
25	City of Pocatello					23,117	0
26	Clear Springs Trout					30,995	0
27	Cold Springs Windfarm					4,406,150	0
28	Coleman Hydro					3,645	0
29	College of Southern Idaho - Pristine Springs #1					53,006	0
30	College of Southern Idaho - Pristine Springs #3					105,479	0
31	Crystal Springs					434,806	0
32	Curry Cattle Company					28,099	0
33	Cycle Horseshoe Bend Wind					1,254,709	0
34	Desert Meadow Windfarm					5,143,775	0
35	Durbin Creek Windfarm					2,024,873	0
36	Durkee Solar					0	(286,404)
37	Eightmile Hydro Project					73,587	0
38	Enerparc Solar Development LLC					0	0
39	Baker Solar Center					1,171,213	0
40	Brush Solar					389,079	0
41	Morgan Solar					431,170	0
42	Ontario Solar Center					385,165	0
43	Vale I Solar					365,306	0

44	Faulkner Ranch Hydro					173,354	0
45	Fossil Gulch Wind					1,213,804	0
46	Hidden Hollow Landfill Gas					153,728	0
47	Golden Valley Wind Park					2,033,243	0
48	Grand View PV Solar Two					13,455,919	0
49	Hammett Hill Windfarm					5,018,693	0
50	Hazelton Wilson Joint Venture					0	0
51	Hazelton B					1,852,153	0
52	Wilson Lake Hydro					2,158,438	0
53	High Mesa Wind Project					4,802,846	0
54	H.K. Hydro Mud Creek S & S					118,681	0
55	Horseshoe Bend Hydro					3,602,488	0
56	Hot Springs Wind Farm					2,570,704	0
57	Hydroland					0	0
58	Elk Creek Hydro					135,486	0
59	Rock Creek II					287,045	0
60	ID Solar 1					5,922,077	0
61	Idaho Winds LLC - Sawtooth Wind Project					5,016,185	0
62	J R Simplot Co.					3,616,857	0
63	J.M. Miller/Sahko Hydro					53,155	0
64	Jett Creek Windfarm					1,944,564	0
65	Kootenai Energy - Fighting Creek					1,616,658	0
66	Koosh Inc. Geo Bon #2					185,106	0
67	Koyle Small Hydro					226,204	0
68	Lateral #10					258,313	0
69	Lemhi Hydro					48,297	0
70	Lemoyne Power Plant					44,442	0
71	Lime Wind Energy					489,714	0
72	Little Mac Power Co.- Cedar Draw					271,718	0
73	Little Wood River Irrigation District					138,672	0
74	Low Line Midway Hydro					469,273	0
75	Lower Low Line - Lowline #2					650,725	0
76	Mainline Windfarm					4,938,174	0
77	Marco Ranches					154,627	0
78	Marysville Hydro Partners-Fall River					3,138,353	0
79	McCollum Enterprises - Canyon Springs					37,787	0

80	MC6 Hydro					321,203	0
81	Milner Dam Wind					3,590,440	0
82	Mt. Home Solar 1, LLC					2,504,432	0
83	Mud Creek White Hydro, Inc					18,996	0
84	Murphy Flat Power, LLC					2,803,715	0
85	North Gooding Main Hydro					373,940	0
86	North Side Energy Company Inc					0	0
87	Bypass					2,233,991	0
88	Hazelton A					2,533,848	0
89	Head of U Canal Project					495,919	0
90	Orchard Ranch Solar, LLC					3,158,090	0
91	Oregon Trail Wind Park					2,483,280	0
92	Owyhee Irrigation District					0	0
93	Mitchell Butte					210,447	0
94	Owyhee Dam C spp					818,991	0
95	Tunnel #1					739,530	0
96	Payne's Ferry Wind Park					4,822,598	0
97	Pico Energy, LLC					561,664	0
98	Pigeon Cove					526,305	0
99	Pilgrim Stage Station Wind Park					2,193,130	0
100	Prospector Windfarm					1,852,956	0
101	Reynolds Irrigation					55,557	0
102	Richard Kaster					0	0
103	Box Canyon					142,172	0
104	Briggs Creek					224,582	0
105	Riverside Hydro - Mora Drop					354,171	0
106	Riverside Investments					0	0
107	Arena Drop					154,756	0
108	Fargo Drop Hydroelectric					309,257	0
109	Rockland Wind Farm					17,608,230	0
110	Ryegrass Windfarm					4,596,054	0
111	Salmon Falls Wind					4,163,420	0
112	Shingle Creek					41,280	0
113	Shorock Hydro Inc.					0	0
114	Rock Creek #1					665,818	0
115	Shoshone Hydro					96,224	0
116	Shoshone #2					183,456	0
117	Simcoe Solar, LLC					3,444,400	0
118	Snake River Pottery					28,221	0

119	Snedigar Ranch Hydro					73,600	0
120	South Forks Joint Venture-Lowline Canal					2,313,460	0
121	Southern Idaho Regional Solid Waste - SISW LFGE					1,859,700	0
122	Spring Water Farms/Fisheries Dev.					15,639	0
123	Tamarack Energy Partnership					785,646	0
124	Tasco - Nampa					0	0
125	Thousand Springs Wind Park					2,019,715	0
126	Tuana Gulch Wind Park					1,948,867	0
127	Tuana Springs Expansion					6,266,599	0
128	Two Ponds Windfarm					5,260,469	0
129	Von Alan Industries - Trout Co					25,092	0
130	White Water Ranch					49,903	0
131	Willow Spring Windfarm					2,382,981	0
132	Wood Hydro					0	0
133	Black Canyon #3					23,077	0
134	Dietrich Drop					900,139	0
135	Jim Knight					108,640	0
136	Magic Reservoir Hydro					566,830	0
137	Mile 28					387,659	0
138	Sagebrush Hydro Project					106,083	0
139	Yahoo Creek Wind Park					4,898,827	0
140	Scheduling Deviation						
141	3PR Trading Inc				0	4,434	0
142	ADM Investor Services, Inc.				0	0	3,252,237
143	AlbertaEX, L.P.				0	960	0
144	Altop Energy Trading LLC				0	2,056,064	0
145	Arizona Public Service Co.				0	201,020	0
146	AVANGRID POWER, LLC				0	3,843,991	0
147	AVANGRID RENEWABLES, LLC				0	0	181
148	Avista Corp.				0	0	1,082
149	Avista Corp.				0	0	245,275
150	Avista Corp.				0	364,114	0
151	Black Mesa Energy, LLC				0	2,836,096	0
152	Bonneville Power Administration				0	0	5,203
153	Bonneville Power Administration				0	0	71,293
154	Bonneville Power Administration				0	522,249	0

155	BP Energy Company				0	74,719	0
156	Brookfield Renewable Trading and Marketing LP				0	151,120	0
157	California Independent System Operator				0	5,957,439	0
158	Calpine Energy Solutions, LLC				0	12,838	0
159	Chelan Co PUD				0	0	89
160	Chelan Co PUD				0	43,928	0
161	Citadel Energy Marketing LLC				0	39,816	0
162	Citigroup Energy Inc.				0	1,768,125	0
163	City of Glendale				0	6,364	0
164	Clatskanie PUD				0	11,614	0
165	ConocoPhillips Company				0	541,244	0
166	Constellation Energy Generation, LLC				0	7,371	0
167	CP Energy Marketing (US) Inc.				0	5,462,989	0
168	Douglas County PUD				0	0	44
169	Dynasty Power Inc.				0	1,952,065	0
170	EDF Trading North America, LLC				0	398,444	0
171	Energy Keepers, Inc				0	322,706	0
172	Franklin Solar LLC				0	7,099,897	0
173	Grant CO Public Utility District #2 -- Electric System				0	0	225
174	Gridforce Energy Management, LLC				0	0	133
175	J.Aron & Company LLC				0	398,444	0
176	Jackpot Holdings, LLC				0	6,042,917	0
177	Macquarie Energy LLC				0	5,039,844	0
178	MAG Energy Solutions Inc.				0	1,107,182	0
179	Mercuria Energy America, LLC				0	3,711,263	0
180	Merrill Lynch Commodities, Inc.				0	0	714,471
181	Morgan Stanley Capital Group Inc.				0	75,306	0
182	Neal Hot Springs Unit #1				0	19,342,744	0
183	Nevada Power Company, dba NV Energy				0	29,000	0
184	NorthWestern Energy				0	0	848
185	NorthWestern Energy				0	0	6,986
186	NorthWestern Energy				0	(144)	0
187	Oregon Solar Customers				0	0	47,764
188	PacifiCorp				0	0	5,439

189	PacifiCorp Inc.				0	0	90,369
190	Phillips 66 Energy Trading LLC				0	19,300,646	0
191	Pleasant Valley Solar LLC				0	664,798	0
192	Portland General Electric Company				0	0	1,716
193	Portland General Electric Company				0	2,692,046	0
194	Powerex Corp.				0	600,761	0
195	Puget Sound Energy, Inc.				0	0	1,731
196	Puget Sound Energy, Inc.				0	253,262	0
197	Raft River Energy I LLC				0	6,413,045	0
198	Rainbow Energy Marketing Corporation				0	24,656	0
199	Salt River Project				0	3,464,782	0
200	Seattle City Light				0	0	544
201	Seattle City Light				0	132,713	0
202	Shell Energy North America (US), L.P.				0	20,214,517	0
203	Sierra Pacific Power Co., dba NV Energy				0	0	695
204	Sierra Pacific Power Co., dba NV Energy				0	212	0
205	Snohomish County PUD				0	24,600	0
206	Tacoma Power				0	0	141
207	Tacoma Power				0	16,750	0
208	Telocaset Wind Power Partners LLC				0	23,312,919	0
209	Tenaska Power Services Co.				0	156,256	0
210	Tenaska Power Services Co.				0	12,000	0
211	The Energy Authority, Inc.				0	418,522	0
212	TransAlta Energy Marketing (U.S.) Inc.				0	4,134,867	0
213	Vitol Inc.				0	55,725	0
214	PacifiCorp Inc.		0	120,109			
215	Clatskanie PUD		63,715	64,090			
216	POWIN LLC						(12,462,239)
217	Jackalope Wind, LLC						(2,639,468)
218	Franklin Battery Storage, LLC						(763,417)
219	Acctg Valuation of Clatskanie PUD						91,369
220	Demand Response Avoided Energy						8,939,724
221	CEYW Excess Generation						15,327,316
222	On-Site Generation - Exports						5,908,066

223	Oregon Community Solar						458,016
224	ADM Investor Services, Inc.						1,008,550
225	Dynasty Power Inc.						16,236
15	TOTAL	0	63,715	184,199	0	361,163,273	20,044,215

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)	...
		Total (k+l+m) of Settlement (\$) (n)
1	AJMS - Little Wood River Ranch II	183,255
2	Arkoosh Hydro - Little Wood River Ranch 1	291,394
3	American Falls Solar, LLC	3,075,027
4	American Falls Solar II, LLC	3,085,178
5	Baker City Hydro	49,298
6	Bannock County Landfill	1,030,550
7	Barber Dam Hydro	397,325
8	Bennett Creek Wind Farm	2,864,812

9	Benson Creek Windfarm	2,055,824
10	Birch Creek	22,974
11	Black Canyon Bliss Hydro	5,748
12	Blind Canyon	255,035
13	Burley Butte Wind Park	3,841,622
14	Camp Reed Wind Park	4,987,544
15	Carroll Family Enterprises/Malad River	88,268
16	Cassia Wind Farm LLC	1,136,323
17	CCP OR Tenant 1, LLC	0
18	Grove Solar Center, LLC	1,125,505
19	Hyline Solar Center, LLC	1,690,201
20	Open Range Solar Center, LLC	1,881,117
21	Railroad Solar Center, LLC	862,306
22	Thunderegg Solar Center, LLC	1,735,391
23	Vale Air Solar Center, LLC	1,751,427
24	City of Hailey	2,253
25	City of Pocatello	23,117
26	Clear Springs Trout	30,995
27	Cold Springs Windfarm	4,406,150
28	Coleman Hydro	3,645
29	College of Southern Idaho - Pristine Springs #1	53,006
30	College of Southern Idaho - Pristine Springs #3	105,479
31	Crystal Springs	434,806
32	Curry Cattle Company	28,099
33	Cycle Horseshoe Bend Wind	1,254,709
34	Desert Meadow Windfarm	5,143,775
35	Durbin Creek Windfarm	2,024,873
36	Durkee Solar	(286,404)
37	Eightmile Hydro Project	73,587
38	Enerparc Solar Development LLC	0
39	Baker Solar Center	1,171,213
40	Brush Solar	389,079
41	Morgan Solar	431,170
42	Ontario Solar Center	385,165
43	Vale I Solar	365,306
44	Faulkner Ranch Hydro	173,354
45	Fossil Gulch Wind	1,213,804
46	Hidden Hollow Landfill Gas	153,728
47	Golden Valley Wind Park	2,033,243
48	Grand View PV Solar Two	13,455,919

49	Hammett Hill Windfarm	5,018,693
50	Hazelton Wilson Joint Venture	0
51	Hazelton B	1,852,153
52	Wilson Lake Hydro	2,158,438
53	High Mesa Wind Project	4,802,846
54	H.K. Hydro Mud Creek S & S	118,681
55	Horseshoe Bend Hydro	3,602,488
56	Hot Springs Wind Farm	2,570,704
57	Hydroland	0
58	Elk Creek Hydro	135,486
59	Rock Creek II	287,045
60	ID Solar 1	5,922,077
61	Idaho Winds LLC - Sawtooth Wind Project	5,016,185
62	J R Simplot Co.	3,616,857
63	J.M. Miller/Sahko Hydro	53,155
64	Jett Creek Windfarm	1,944,564
65	Kootenai Energy - Fighting Creek	1,616,658
66	Koosh Inc. Geo Bon #2	185,106
67	Koyle Small Hydro	226,204
68	Lateral #10	258,313
69	Lemhi Hydro	48,297
70	Lemoyne Power Plant	44,442
71	Lime Wind Energy	489,714
72	Little Mac Power Co.- Cedar Draw	271,718
73	Little Wood River Irrigation District	138,672
74	Low Line Midway Hydro	469,273
75	Lower Low Line - Lowline #2	650,725
76	Mainline Windfarm	4,938,174
77	Marco Ranches	154,627
78	Marysville Hydro Partners- Fall River	3,138,353
79	McCollum Enterprises -Canyon Springs	37,787
80	MC6 Hydro	321,203
81	Milner Dam Wind	3,590,440
82	Mt. Home Solar 1, LLC	2,504,432
83	Mud Creek White Hydro, Inc	18,996
84	Murphy Flat Power, LLC	2,803,715
85	North Gooding Main Hydro	373,940
86	North Side Energy Company Inc	0
87	Bypass	2,233,991
88	Hazelton A	2,533,848

89	Head of U Canal Project	495,919
90	Orchard Ranch Solar, LLC	3,158,090
91	Oregon Trail Wind Park	2,483,280
92	Owyhee Irrigation District	0
93	Mitchell Butte	210,447
94	Owyhee Dam Cspp	818,991
95	Tunnel #1	739,530
96	Payne's Ferry Wind Park	4,822,598
97	Pico Energy, LLC	561,664
98	Pigeon Cove	526,305
99	Pilgrim Stage Station Wind Park	2,193,130
100	Prospector Windfarm	1,852,956
101	Reynolds Irrigation	55,557
102	Richard Kaster	0
103	Box Canyon	142,172
104	Briggs Creek	224,582
105	Riverside Hydro - Mora Drop	354,171
106	Riverside Investments	0
107	Arena Drop	154,756
108	Fargo Drop Hydroelectric	309,257
109	Rockland Wind Farm	17,608,230
110	Ryegrass Windfarm	4,596,054
111	Salmon Falls Wind	4,163,420
112	Shingle Creek	41,280
113	Shorock Hydro Inc.	0
114	Rock Creek #1	665,818
115	Shoshone Hydro	96,224
116	Shoshone #2	183,456
117	Simcoe Solar, LLC	3,444,400
118	Snake River Pottery	28,221
119	Snedigar Ranch Hydro	73,600
120	South Forks Joint Venture-Lowline Canal	2,313,460
121	Southern Idaho Regional Solid Waste - SISW LFGE	1,859,700
122	Spring Water Farms/Fisheries Dev.	15,639
123	Tamarack Energy Partnership	785,646
124	Tasco - Nampa	0
125	Thousand Springs Wind Park	2,019,715
126	Tuana Gulch Wind Park	1,948,867
127	Tuana Springs Expansion	6,266,599
128	Two Ponds Windfarm	5,260,469

129	Von Alan Industries - Trout Co	25,092
130	White Water Ranch	49,903
131	Willow Spring Windfarm	2,382,981
132	Wood Hydro	0
133	Black Canyon #3	23,077
134	Dietrich Drop	900,139
135	Jim Knight	108,640
136	Magic Reservoir Hydro	566,830
137	Mile 28	387,659
138	Sagebrush Hydro Project	106,083
139	Yahoo Creek Wind Park	4,898,827
140	Scheduling Deviation	0
141	3PR Trading Inc	4,434
142	ADM Investor Services, Inc.	3,252,237
143	AlbertaEX, L.P.	960
144	Altop Energy Trading LLC	2,056,064
145	Arizona Public Service Co.	201,020
146	AVANGRID POWER, LLC	3,843,991
147	AVANGRID RENEWABLES, LLC	181
148	Avista Corp.	1,082
149	Avista Corp.	245,275
150	Avista Corp.	364,114
151	Black Mesa Energy, LLC	2,836,096
152	Bonneville Power Administration	5,203
153	Bonneville Power Administration	71,293
154	Bonneville Power Administration	522,249
155	BP Energy Company	74,719
156	Brookfield Renewable Trading and Marketing LP	151,120
157	California Independent System Operator	5,957,439
158	Calpine Energy Solutions, LLC	12,838
159	Chelan Co PUD	89
160	Chelan Co PUD	43,928
161	Citadel Energy Marketing LLC	39,816
162	Citigroup Energy Inc.	1,768,125
163	City of Glendale	6,364
164	Clatskanie PUD	11,614
165	ConocoPhillips Company	541,244
166	Constellation Energy Generation, LLC	7,371
167	CP Energy Marketing (US) Inc.	5,462,989
168	Douglas County PUD	44

169	Dynasty Power Inc.	1,952,065
170	EDF Trading North America, LLC	398,444
171	Energy Keepers, Inc	322,706
172	Franklin Solar LLC	7,099,897
173	Grant CO Public Utility District #2 -- Electric System	225
174	Gridforce Energy Management, LLC	133
175	J.Aron & Company LLC	398,444
176	Jackpot Holdings, LLC	6,042,917
177	Macquarie Energy LLC	5,039,844
178	MAG Energy Solutions Inc.	1,107,182
179	Mercuria Energy America, LLC	3,711,263
180	Merrill Lynch Commodities, Inc.	714,471
181	Morgan Stanley Capital Group Inc.	75,306
182	Neal Hot Springs Unit #1	19,342,744
183	Nevada Power Company, dba NV Energy	29,000
184	NorthWestern Energy	848
185	NorthWestern Energy	6,986
186	NorthWestern Energy	(144)
187	Oregon Solar Customers	47,764
188	PacifiCorp	5,439
189	PacifiCorp Inc.	90,369
190	Phillips 66 Energy Trading LLC	19,300,646
191	Pleasant Valley Solar LLC	664,798
192	Portland General Electric Company	1,716
193	Portland General Electric Company	2,692,046
194	Powerex Corp.	600,761
195	Puget Sound Energy, Inc.	1,731
196	Puget Sound Energy, Inc.	253,262
197	Raft River Energy I LLC	6,413,045
198	Rainbow Energy Marketing Corporation	24,656
199	Salt River Project	3,464,782
200	Seattle City Light	544
201	Seattle City Light	132,713
202	Shell Energy North America (US), L.P.	20,214,517
203	Sierra Pacific Power Co., dba NV Energy	695
204	Sierra Pacific Power Co., dba NV Energy	212
205	Snohomish County PUD	24,600
206	Tacoma Power	141
207	Tacoma Power	16,750
208	Telocaset Wind Power Partners LLC	23,312,919

209	Tenaska Power Services Co.	156,256
210	Tenaska Power Services Co.	12,000
211	The Energy Authority, Inc.	418,522
212	TransAlta Energy Marketing (U.S.) Inc.	4,134,867
213	Vitol Inc.	55,725
214	PacifiCorp Inc.	0
215	Clatskanie PUD	0
216	POWIN LLC	(12,462,239)
217	Jackalope Wind, LLC	(2,639,468)
218	Franklin Battery Storage, LLC	(763,417)
219	Acctg Valuation of Clatskanie PUD	91,369
220	Demand Response Avoided Energy	8,939,724
221	CEYW Excess Generation	15,327,316
222	On-Site Generation - Exports	5,908,066
223	Oregon Community Solar	458,016
224	ADM Investor Services, Inc.	1,008,550
225	Dynasty Power Inc.	16,236
15	TOTAL	381,207,488

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode
Ida West, a subsidiary of IdaCorp (Idaho Power Company's parent company), has partial ownership of these projects
(b) Concept: StatisticalClassificationCode
Ida West, a subsidiary of IdaCorp (Idaho Power Company's parent company), has partial ownership of these projects
(c) Concept: StatisticalClassificationCode
Ida West, a subsidiary of IdaCorp (Idaho Power Company's parent company), has partial ownership of these projects
(d) Concept: StatisticalClassificationCode
Heinz-Odom, Chandra: Non Firm Purchases
(e) Concept: StatisticalClassificationCode
Difference between booked and scheduled energy
(f) Concept: StatisticalClassificationCode
ADM Investor Services, Inc Futures Account Document, dated May 6, 2015
(g) Concept: StatisticalClassificationCode
Non Firm Purchases
(h) Concept: StatisticalClassificationCode
Spinning or Operating Reserves
(i) Concept: StatisticalClassificationCode
Spinning or Operating Reserves
(j) Concept: StatisticalClassificationCode
Financial Transmission Losses
(k) Concept: StatisticalClassificationCode
Spinning or Operating Reserves
(l) Concept: StatisticalClassificationCode
Financial Transmission Losses
(m) Concept: StatisticalClassificationCode
Spinning or Operating Reserves
(n) Concept: StatisticalClassificationCode
Spinning or Operating Reserves
(o) Concept: StatisticalClassificationCode
Spinning or Operating Reserves
(p) Concept: StatisticalClassificationCode
Spinning or Operating Reserves
(q) Concept: StatisticalClassificationCode
ISDA Master Agreement With Merrill Lynch Commodities, Inc. dated 09/24/13
(r) Concept: StatisticalClassificationCode
Spinning or Operating Reserves

(s) Concept: StatisticalClassificationCode
Financial Transmission Losses
(t) Concept: StatisticalClassificationCode
Schedule 88 Oregon Solar
(u) Concept: StatisticalClassificationCode
Spinning or Operating Reserves
(v) Concept: StatisticalClassificationCode
Financial Transmission Losses
(w) Concept: StatisticalClassificationCode
Spinning or Operating Reserves
(x) Concept: StatisticalClassificationCode
Spinning or Operating Reserves
(y) Concept: StatisticalClassificationCode
Spinning or Operating Reserves
(z) Concept: StatisticalClassificationCode
Financial Transmission Losses
(aa) Concept: StatisticalClassificationCode
Spinning or Operating Reserves
(ab) Concept: StatisticalClassificationCode
June 2021 FERC Ruling Reversal Refund
(ac) Concept: StatisticalClassificationCode
Physical Transmission Losses
(ad) Concept: StatisticalClassificationCode
Damages for lost energy production
(ae) Concept: StatisticalClassificationCode
Damages for lost energy production
(af) Concept: StatisticalClassificationCode
Damages for lost energy production
(ag) Concept: StatisticalClassificationCode
Energy exchange between Clatskanie PUD and Idaho Power Company at Arrowrock Dam
(ah) Concept: StatisticalClassificationCode
Incentive program for customers to reduce demand during peak hours
(ai) Concept: StatisticalClassificationCode
Excess Generation Purchased from Clean Energy Your Way projects
(aj) Concept: StatisticalClassificationCode
Excess generation from distributed energy resources
(ak) Concept: StatisticalClassificationCode
Excess generation from Oregon community solar project
(al) Concept: StatisticalClassificationCode
Purchase of California CARB Allowances

(an) Concept: StatisticalClassificationCode

Carbon cost adjustments passed by counterparty

(an) Concept: OtherChargesOfPurchasedPower

Mechanical Availability Guarantee Damages

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

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

- 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.
- Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
- 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).
- 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.
- 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.
- 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.
- 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.
- Report in column (i) and (j) the total megawatthours received and delivered.
- 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.
- 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.
- 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)
1	^(a) Bonneville Power Administration - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	FNO	^(e) 9	
2	^(b) Bonneville Power Administration - USBR	Bonneville Power Administration	United States Bureau of Reclamation	FNO	9	
3	^(c) Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	FNO	9	
4	^(d) Milner Irrigation District	United States Bureau of Reclamation	Milner Irrigation District	OLF	^(e) Legacy	Minidoka, Idaho
5	Seattle City Light	Seattle City Light	Bonneville Power Administration	OS	^(e) 5/6	
6	^(f) PacifiCorp	PacifiCorp West	PacifiCorp West	FNO	9	
7	^(g) United States Bureau of Indian Affairs	Bonneville Power Administration	United States Bureau of Indian Affairs	OS	Legacy	LaGrande, Oregon
8	AmpRenew Offtake I LLC			OS	5/6	
9	West Point RNG LLC			OS	5/6	
10	AmpRenew Offtake I LLC	Idaho Power Company	Sierra Pacific Power	LFP	7/8	MDSK
11	Bonneville Power Administration	PacifiCorp West	PacifiCorp East	LFP	7/8	M500
12	Bonneville Power Administration	PacifiCorp West	PacifiCorp East	LFP	7/8	SMLK
13	Energy Keepers, Inc.	PacifiCorp East	Sierra Pacific Power	LFP	7/8	BRDY

14	Mercuria Energy America, LLC	PacifiCorp East	Sierra Pacific Power	LFP	7/8	JBSN
15	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	LFP	7/8	BORA
16	PacifiCorp Inc.	PacifiCorp East	Bonneville Power Administration	LFP	7/8	BORA
17	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	LFP	7/8	KPRT
18	Powerex Corporation	Avista	PacifiCorp East	LFP	7/8	LOLO
19	Seattle City Light	Idaho Power Company	Bonneville Power Administration	LFP	7/8	LYPK
20	West Point RNG LLC	Idaho Power Company	Sierra Pacific Power	LFP	7/8	MDSK
21	Adapture Renewables, Inc. (Morgan Solar)			NF	11	
22	Adapture Renewables, Inc. (Ontario Solar Center)			NF	7/8	
23	Adapture Renewables, Inc. (Vale I Solar)			NF	7/8	
24	Altop Energy Trading, LLC	PacifiCorp East	PacifiCorp West	NF	7/8	BORA
25	Altop Energy Trading, LLC	PacifiCorp East	Bonneville Power Administration	NF	7/8	BORA
26	Altop Energy Trading, LLC	PacifiCorp East	Avista	NF	7/8	BORA
27	Altop Energy Trading, LLC	PacifiCorp East	Bonneville Power Administration	NF	7/8	BRDY
28	Altop Energy Trading, LLC	PacifiCorp East	Avista	NF	7/8	BRDY
29	Altop Energy Trading, LLC	PacifiCorp East	Sierra Pacific Power	NF	7/8	BRDY
30	Altop Energy Trading, LLC	PacifiCorp West	PacifiCorp East	NF	7/8	HURR
31	Altop Energy Trading, LLC	Idaho Power Company	Avista	NF	7/8	IPCOGEN
32	Altop Energy Trading, LLC	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
33	Altop Energy Trading, LLC	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE
34	Altop Energy Trading, LLC	Bonneville Power Administration	Sierra Pacific Power	SFP	7/8	LAGRANDE
35	Altop Energy Trading, LLC	Sierra Pacific Power	PacifiCorp West	NF	7/8	M345
36	Altop Energy Trading, LLC	Sierra Pacific Power	PacifiCorp West	SFP	7/8	M345
37	Altop Energy Trading, LLC	Sierra Pacific Power	Idaho Power Company	NF	7/8	M345
38	Altop Energy Trading, LLC	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
39	Altop Energy Trading, LLC	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
40	Altop Energy Trading, LLC	Sierra Pacific Power	Bonneville Power Administration	SFP	7/8	M345
41	Altop Energy Trading, LLC	Sierra Pacific Power	Avista	NF	7/8	M345

42	Altop Energy Trading, LLC	PacifiCorp West	PacifiCorp East	NF	7/8	SMLK
43	Altop Energy Trading, LLC	Idaho Power Company	Sierra Pacific Power	NF	7/8	WALLAWALLA
44	Arizona Public Service			NF	7/8	
45	Avangrid Renewables, LLC	PacifiCorp East	PacifiCorp West	NF	7/8	BORA
46	Avangrid Renewables, LLC	PacifiCorp East	Bonneville Power Administration	NF	7/8	BORA
47	Avangrid Renewables, LLC	PacifiCorp East	Avista	NF	7/8	BORA
48	Avangrid Renewables, LLC	PacifiCorp East	Bonneville Power Administration	NF	7/8	BRDY
49	Avangrid Renewables, LLC	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
50	Avangrid Renewables, LLC	PacifiCorp West	PacifiCorp East	NF	7/8	SMLK
51	Avista Corporation	PacifiCorp East	Avista	NF	7/8	BRDY
52	Benson Creek Windfarm, LLC			NF	11	
53	Bonneville Power Administration	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	BPAT.NWMT
54	Bonneville Power Administration	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	BPAT.NWMT
55	Bonneville Power Administration	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF	7/8	BPAT.NWMT
56	Bonneville Power Administration	PacifiCorp East	PacifiCorp East	NF	7/8	JBSN
57	Bonneville Power Administration	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
58	Bonneville Power Administration	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
59	Bonneville Power Administration	Bonneville Power Administration	PacifiCorp East	SFP	7/8	LAGRANDE
60	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	NF	7/8	LAGRANDE
61	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	SFP	7/8	LAGRANDE
62	Bonneville Power Administration	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE
63	Bonneville Power Administration	Bonneville Power Administration	Sierra Pacific Power	SFP	7/8	LAGRANDE
64	Bonneville Power Administration	Avista	PacifiCorp East	NF	7/8	LOLO
65	Bonneville Power Administration	Avista	PacifiCorp East	SFP	7/8	LOLO
66	Bonneville Power Administration	Avista	PacifiCorp East	NF	7/8	LOLO
67	Bonneville Power Administration	Avista	PacifiCorp East	NF	7/8	LOLO
68	Bonneville Power Administration	Avista	Bonneville Power Administration	NF	7/8	LOLO
69	Bonneville Power Administration	PacifiCorp West	PacifiCorp East	NF	7/8	SMLK

70	Bonneville Power Administration	PacifiCorp West	Sierra Pacific Power	NF	7/8	SMLK
71	Brookfield Renewable Trading & Marketing			NF	7/8	
72	CP Energy Marketing (US) Inc.	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
73	Durbin Creek Windfarm, LLC			NF	11	
74	Dynasty Power Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	BORA
75	Dynasty Power Inc.	PacifiCorp East	Avista	NF	7/8	BORA
76	Dynasty Power Inc.	PacifiCorp East	Avista	SFP	7/8	BORA
77	Dynasty Power Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	BPAT.NWMT
78	Dynasty Power Inc.	NorthWestern/PacifiCorp East	Avista	NF	7/8	BPAT.NWMT
79	Dynasty Power Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF	7/8	BPAT.NWMT
80	Dynasty Power Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	BRDY
81	Dynasty Power Inc.	PacifiCorp East	Avista	NF	7/8	BRDY
82	Dynasty Power Inc.	PacifiCorp East	Sierra Pacific Power	NF	7/8	BRDY
83	Dynasty Power Inc.	PacifiCorp East	PacifiCorp West	SFP	7/8	GSHN
84	Dynasty Power Inc.	PacifiCorp East	PacifiCorp West	SFP	7/8	GSHN
85	Dynasty Power Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	GSHN
86	Dynasty Power Inc.	PacifiCorp East	Avista	SFP	7/8	GSHN
87	Dynasty Power Inc.	PacifiCorp East	PacifiCorp West	NF	7/8	JBSN
88	Dynasty Power Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	JBSN
89	Dynasty Power Inc.	PacifiCorp East	Avista	NF	7/8	JBSN
90	Dynasty Power Inc.	PacifiCorp East	Sierra Pacific Power	NF	7/8	JBSN
91	Dynasty Power Inc.	Bonneville Power Administration	Avista	NF	7/8	LAGRANDE
92	Dynasty Power Inc.	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE
93	Dynasty Power Inc.	Avista	Sierra Pacific Power	NF	7/8	LOLO
94	Dynasty Power Inc.	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
95	Dynasty Power Inc.	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
96	Dynasty Power Inc.	Sierra Pacific Power	PacifiCorp West	SFP	7/8	M345
97	Dynasty Power Inc.	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
98	Dynasty Power Inc.	Sierra Pacific Power	Avista	NF	7/8	M345
99	Dynasty Power Inc.	Sierra Pacific Power	Avista	SFP	7/8	M345
100	Dynasty Power Inc.	Idaho Power Company	PacifiCorp East	NF	7/8	WALLAWALLA
101	EDF Trading North America, LLC	PacifiCorp East	PacifiCorp East	NF	7/8	JEFF
102	EDF Trading North America, LLC	PacifiCorp East	Sierra Pacific Power	NF	7/8	JEFF

103	EDF Trading North America, LLC	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
104	Energy Keepers, Inc.	Idaho Power Company	PacifiCorp East	NF	7/8	BGSY
105	Energy Keepers, Inc.	Idaho Power Company	PacifiCorp East	SFP	7/8	BGSY
106	Energy Keepers, Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	SFP	7/8	BRDY
107	Energy Keepers, Inc.	PacifiCorp East	PacifiCorp East	NF	7/8	BRDY
108	Energy Keepers, Inc.	PacifiCorp East	PacifiCorp East	SFP	7/8	BRDY
109	Energy Keepers, Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	BRDY
110	Energy Keepers, Inc.	PacifiCorp East	Avista	NF	7/8	BRDY
111	Energy Keepers, Inc.	PacifiCorp East	Sierra Pacific Power	NF	7/8	GSHN
112	Energy Keepers, Inc.	PacifiCorp East	PacifiCorp East	NF	7/8	JBSN
113	Energy Keepers, Inc.	PacifiCorp East	Avista	NF	7/8	JBSN
114	Energy Keepers, Inc.	PacifiCorp East	Idaho Power Company	NF	7/8	JEFF
115	Energy Keepers, Inc.	PacifiCorp East	PacifiCorp East	NF	7/8	JEFF
116	Energy Keepers, Inc.	PacifiCorp East	PacifiCorp East	SFP	7/8	JEFF
117	Energy Keepers, Inc.	PacifiCorp East	PacifiCorp East	SFP	7/8	JEFF
118	Energy Keepers, Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	JEFF
119	Energy Keepers, Inc.	PacifiCorp East	Avista	NF	7/8	JEFF
120	Energy Keepers, Inc.	PacifiCorp East	Sierra Pacific Power	NF	7/8	JEFF
121	Energy Keepers, Inc.	PacifiCorp East	Sierra Pacific Power	SFP	7/8	JEFF
122	Energy Keepers, Inc.	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE
123	Energy Keepers, Inc.	Avista	Sierra Pacific Power	NF	7/8	LOLO
124	Energy Keepers, Inc.	Idaho Power Company	Sierra Pacific Power	NF	7/8	LYPK
125	Energy Keepers, Inc.	Idaho Power Company	Sierra Pacific Power	SFP	7/8	LYPK
126	Energy Keepers, Inc.	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
127	Energy Keepers, Inc.	Sierra Pacific Power	PacifiCorp East	SFP	7/8	M345
128	Energy Keepers, Inc.	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
129	Energy Keepers, Inc.	Sierra Pacific Power	Avista	NF	7/8	M345
130	Guzman Energy Group LLC	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	AVAT.NWMT
131	Guzman Energy Group LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF	7/8	AVAT.NWMT
132	Guzman Energy Group LLC	Idaho Power Company	PacifiCorp East	NF	7/8	BGSY
133	Guzman Energy Group LLC	PacifiCorp East	PacifiCorp West	SFP	7/8	BORA
134	Guzman Energy Group LLC	PacifiCorp East	Bonneville Power Administration	NF	7/8	BORA
135	Guzman Energy Group LLC	PacifiCorp East	Avista	NF	7/8	BORA
136	Guzman Energy Group LLC	PacifiCorp East	Avista	SFP	7/8	BORA

137	Guzman Energy Group LLC	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	BPAT.NWMT
138	Guzman Energy Group LLC	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	BPAT.NWMT
139	Guzman Energy Group LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF	7/8	BPAT.NWMT
140	Guzman Energy Group LLC	PacifiCorp East	PacifiCorp East	NF	7/8	BRDY
141	Guzman Energy Group LLC	PacifiCorp East	PacifiCorp West	NF	7/8	BRDY
142	Guzman Energy Group LLC	PacifiCorp East	Avista	NF	7/8	BRDY
143	Guzman Energy Group LLC	PacifiCorp East	Sierra Pacific Power	NF	7/8	BRDY
144	Guzman Energy Group LLC	PacifiCorp East	NorthWestern/PacifiCorp East	NF	7/8	GSHN
145	Guzman Energy Group LLC	PacifiCorp West	PacifiCorp East	NF	7/8	H500
146	Guzman Energy Group LLC	PacifiCorp West	Sierra Pacific Power	NF	7/8	H500
147	Guzman Energy Group LLC	PacifiCorp West	PacifiCorp East	NF	7/8	HURR
148	Guzman Energy Group LLC	PacifiCorp East	PacifiCorp East	NF	7/8	JBSN
149	Guzman Energy Group LLC	PacifiCorp East	Bonneville Power Administration	NF	7/8	JBSN
150	Guzman Energy Group LLC	PacifiCorp East	Avista	NF	7/8	JBSN
151	Guzman Energy Group LLC	PacifiCorp East	Sierra Pacific Power	NF	7/8	JBSN
152	Guzman Energy Group LLC	PacifiCorp East	Bonneville Power Administration	NF	7/8	JEFF
153	Guzman Energy Group LLC	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
154	Guzman Energy Group LLC	Bonneville Power Administration	PacifiCorp West	NF	7/8	LAGRANDE
155	Guzman Energy Group LLC	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
156	Guzman Energy Group LLC	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE
157	Guzman Energy Group LLC	Avista	PacifiCorp East	NF	7/8	LOLO
158	Guzman Energy Group LLC	Avista	PacifiCorp East	NF	7/8	LOLO
159	Guzman Energy Group LLC	Avista	Sierra Pacific Power	NF	7/8	LOLO
160	Guzman Energy Group LLC	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
161	Guzman Energy Group LLC	Sierra Pacific Power	Avista	NF	7/8	M345
162	Guzman Energy Group LLC	Idaho Power Company	PacifiCorp East	NF	7/8	WALLAWALLA
163	Idaho Wind Partners 1, LLC (Pilgrim Stage Station Wind)			NF	11	

164	Jett Creek Windfarm, LLC			NF	11	
165	Macquarie Energy, LLC	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF	7/8	AVAT.NWMT
166	Macquarie Energy, LLC	PacifiCorp East	PacifiCorp East	NF	7/8	BORA
167	Macquarie Energy, LLC	PacifiCorp East	Bonneville Power Administration	NF	7/8	BORA
168	Macquarie Energy, LLC	PacifiCorp East	Avista	NF	7/8	BORA
169	Macquarie Energy, LLC	PacifiCorp East	Bonneville Power Administration	NF	7/8	BRDY
170	Macquarie Energy, LLC	PacifiCorp East	Avista	NF	7/8	BRDY
171	Macquarie Energy, LLC	PacifiCorp East	Sierra Pacific Power	SFP	7/8	BRDY
172	Macquarie Energy, LLC	PacifiCorp East	PacifiCorp East	NF	7/8	JBSN
173	Macquarie Energy, LLC	PacifiCorp East	Bonneville Power Administration	NF	7/8	JBSN
174	Macquarie Energy, LLC	PacifiCorp East	Avista	NF	7/8	JEFF
175	Macquarie Energy, LLC	PacifiCorp East	Sierra Pacific Power	NF	7/8	JEFF
176	Macquarie Energy, LLC	PacifiCorp East	Sierra Pacific Power	SFP	7/8	JEFF
177	Macquarie Energy, LLC	Bonneville Power Administration	NorthWestern/PacifiCorp East	NF	7/8	LAGRANDE
178	Macquarie Energy, LLC	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE
179	Macquarie Energy, LLC	Avista	Bonneville Power Administration	NF	7/8	LOLO
180	Macquarie Energy, LLC	Avista	Sierra Pacific Power	NF	7/8	LOLO
181	Macquarie Energy, LLC	Sierra Pacific Power	NorthWestern/PacifiCorp East	SFP	7/8	M345
182	Macquarie Energy, LLC	Sierra Pacific Power	NorthWestern/PacifiCorp East	SFP	7/8	M345
183	Macquarie Energy, LLC	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
184	Macquarie Energy, LLC	Sierra Pacific Power	PacifiCorp East	SFP	7/8	M345
185	Macquarie Energy, LLC	Sierra Pacific Power	PacifiCorp West	NF	7/8	M345
186	Macquarie Energy, LLC	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
187	Macquarie Energy, LLC	Sierra Pacific Power	Bonneville Power Administration	SFP	7/8	M345
188	Macquarie Energy, LLC	Sierra Pacific Power	Avista	NF	7/8	M345
189	Macquarie Energy, LLC	Sierra Pacific Power	Avista	SFP	7/8	M345
190	Mag Energy Solutions	PacifiCorp East	PacifiCorp West	NF	7/8	BORA
191	Mag Energy Solutions	PacifiCorp East	PacifiCorp West	NF	7/8	BORA
192	Mag Energy Solutions	PacifiCorp East	Bonneville Power Administration	NF	7/8	BORA
193	Mag Energy Solutions	PacifiCorp East	Sierra Pacific Power	NF	7/8	JBSN
194	Mag Energy Solutions	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE
195	Mag Energy Solutions	Bonneville Power Administration	Sierra Pacific Power	SFP	7/8	LAGRANDE
196	Mag Energy Solutions	Avista	Bonneville Power Administration	NF	7/8	LOLO
197	Mag Energy Solutions	Sierra Pacific Power	PacifiCorp East	SFP	7/8	M345

198	Mag Energy Solutions	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
199	Mag Energy Solutions	Sierra Pacific Power	Bonneville Power Administration	SFP	7/8	M345
200	Mag Energy Solutions	Sierra Pacific Power	Avista	NF	7/8	M345
201	Mag Energy Solutions	Sierra Pacific Power	Avista	SFP	7/8	M345
202	Mercuria Energy America, LLC	PacifiCorp East	PacifiCorp West	NF	7/8	BORA
203	Mercuria Energy America, LLC	PacifiCorp East	Bonneville Power Administration	NF	7/8	BORA
204	Mercuria Energy America, LLC	PacifiCorp East	PacifiCorp East	SFP	7/8	JBSN
205	Mercuria Energy America, LLC	PacifiCorp East	PacifiCorp West	NF	7/8	JBSN
206	Mercuria Energy America, LLC	PacifiCorp East	PacifiCorp West	SFP	7/8	JBSN
207	Mercuria Energy America, LLC	PacifiCorp East	PacifiCorp West	NF	7/8	JBSN
208	Mercuria Energy America, LLC	PacifiCorp East	PacifiCorp West	SFP	7/8	JBSN
209	Mercuria Energy America, LLC	PacifiCorp East	Bonneville Power Administration	SFP	7/8	JBSN
210	Mercuria Energy America, LLC	PacifiCorp East	Avista	NF	7/8	JBSN
211	Mercuria Energy America, LLC	PacifiCorp East	Avista	SFP	7/8	JBSN
212	Mercuria Energy America, LLC	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
213	Mercuria Energy America, LLC	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
214	Mercuria Energy America, LLC	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
215	MFT Energy US Power LLC	PacifiCorp East	PacifiCorp East	NF	7/8	BRDY
216	MFT Energy US Power LLC	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
217	Morgan Stanley Capital Group. Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	AVAT.NWMT
218	Morgan Stanley Capital Group. Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	AVAT.NWMT
219	Morgan Stanley Capital Group. Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF	7/8	AVAT.NWMT
220	Morgan Stanley Capital Group. Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF	7/8	AVAT.NWMT
221	Morgan Stanley Capital Group. Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP	7/8	AVAT.NWMT
222	Morgan Stanley Capital Group. Inc.	PacifiCorp East	PacifiCorp East	NF	7/8	BORA
223	Morgan Stanley Capital Group. Inc.	PacifiCorp East	PacifiCorp West	NF	7/8	BORA
224	Morgan Stanley Capital Group. Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	BORA
225	Morgan Stanley Capital Group. Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	BPAT.NWMT

226	Morgan Stanley Capital Group. Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	BPAT.NWMT
227	Morgan Stanley Capital Group. Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF	7/8	BPAT.NWMT
228	Morgan Stanley Capital Group. Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF	7/8	BPAT.NWMT
229	Morgan Stanley Capital Group. Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	BRDY
230	Morgan Stanley Capital Group. Inc.	PacifiCorp East	Bonneville Power Administration	SFP	7/8	BRDY
231	Morgan Stanley Capital Group. Inc.	PacifiCorp East	Avista	NF	7/8	BRDY
232	Morgan Stanley Capital Group. Inc.	PacifiCorp East	Sierra Pacific Power	NF	7/8	BRDY
233	Morgan Stanley Capital Group. Inc.	PacifiCorp East	Sierra Pacific Power	SFP	7/8	BRDY
234	Morgan Stanley Capital Group. Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	GSHN
235	Morgan Stanley Capital Group. Inc.	PacifiCorp East	Avista	NF	7/8	GSHN
236	Morgan Stanley Capital Group. Inc.	PacifiCorp East	Sierra Pacific Power	NF	7/8	GSHN
237	Morgan Stanley Capital Group. Inc.	PacifiCorp West	Sierra Pacific Power	NF	7/8	H500
238	Morgan Stanley Capital Group. Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	JBSN
239	Morgan Stanley Capital Group. Inc.	PacifiCorp East	Avista	NF	7/8	JBSN
240	Morgan Stanley Capital Group. Inc.	PacifiCorp East	Sierra Pacific Power	NF	7/8	JBSN
241	Morgan Stanley Capital Group. Inc.	PacifiCorp East	PacifiCorp East	NF	7/8	JEFF
242	Morgan Stanley Capital Group. Inc.	PacifiCorp East	PacifiCorp East	NF	7/8	JEFF
243	Morgan Stanley Capital Group. Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	JEFF
244	Morgan Stanley Capital Group. Inc.	PacifiCorp East	Avista	NF	7/8	JEFF
245	Morgan Stanley Capital Group. Inc.	PacifiCorp East	Sierra Pacific Power	NF	7/8	JEFF
246	Morgan Stanley Capital Group. Inc.	PacifiCorp East	Sierra Pacific Power	SFP	7/8	JEFF
247	Morgan Stanley Capital Group. Inc.	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
248	Morgan Stanley Capital Group. Inc.	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
249	Morgan Stanley Capital Group. Inc.	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE
250	Morgan Stanley Capital Group. Inc.	Avista	PacifiCorp East	NF	7/8	LOLO
251	Morgan Stanley Capital Group. Inc.	Avista	Sierra Pacific Power	NF	7/8	LOLO
252	Morgan Stanley Capital Group. Inc.	Idaho Power Company	Bonneville Power Administration	NF	7/8	LYPK

253	Morgan Stanley Capital Group. Inc.	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
254	Morgan Stanley Capital Group. Inc.	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
255	Morgan Stanley Capital Group. Inc.	Sierra Pacific Power	Avista	NF	7/8	M345
256	Morgan Stanley Capital Group. Inc.	PacifiCorp West	PacifiCorp East	NF	7/8	SMLK
257	Morgan Stanley Capital Group. Inc.	PacifiCorp West	Sierra Pacific Power	NF	7/8	SMLK
258	Morgan Stanley Capital Group. Inc.	Idaho Power Company	PacifiCorp East	NF	7/8	WALLAWALLA
259	Morgan Stanley Capital Group. Inc.	Idaho Power Company	Sierra Pacific Power	NF	7/8	WALLAWALLA
260	Nevada Power Company d/b/a NV Energy	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE
261	NorthWestern Energy	PacifiCorp East	Bonneville Power Administration	NF	7/8	BRDY
262	PacifiCorp Inc.	PacifiCorp East	Avista	NF	7/8	BORA
263	PacifiCorp Inc.	PacifiCorp East	Avista	SFP	7/8	BORA
264	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	SFP	7/8	BRDY
265	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	NF	7/8	BRDY
266	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	SFP	7/8	BRDY
267	PacifiCorp Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	BRDY
268	PacifiCorp Inc.	PacifiCorp East	Avista	NF	7/8	BRDY
269	PacifiCorp Inc.	PacifiCorp East	Idaho Power Company	NF	7/8	JEFF
270	PacifiCorp Inc.	PacifiCorp East	Idaho Power Company	SFP	7/8	JEFF
271	PacifiCorp Inc.	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
272	PacifiCorp Inc.	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
273	PacifiCorp Inc.	Avista	PacifiCorp East	NF	7/8	LOLO
274	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF	7/8	SMLK
275	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF	7/8	WALLAWALLA
276	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF	7/8	WALLAWALLA
277	Phillips 66 Energy Trading LLC	Idaho Power Company	PacifiCorp East	SFP	7/8	BGSY
278	Phillips 66 Energy Trading LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF	7/8	BPAT.NWMT
279	Phillips 66 Energy Trading LLC	PacifiCorp East	NorthWestern/PacifiCorp East	SFP	7/8	BRDY
280	Phillips 66 Energy Trading LLC	PacifiCorp East	Bonneville Power Administration	NF	7/8	BRDY
281	Phillips 66 Energy Trading LLC	PacifiCorp East	Bonneville Power Administration	SFP	7/8	BRDY
282	Phillips 66 Energy Trading LLC	PacifiCorp East	Avista	NF	7/8	BRDY
283	Phillips 66 Energy Trading LLC	PacifiCorp East	Avista	SFP	7/8	BRDY

284	Phillips 66 Energy Trading LLC	PacifiCorp East	Sierra Pacific Power	NF	7/8	BRDY
285	Phillips 66 Energy Trading LLC	PacifiCorp East	Sierra Pacific Power	SFP	7/8	BRDY
286	Phillips 66 Energy Trading LLC	Idaho Power Company	PacifiCorp East	SFP	7/8	IPCOGEN
287	Phillips 66 Energy Trading LLC	PacifiCorp East	PacifiCorp East	NF	7/8	JBSN
288	Phillips 66 Energy Trading LLC	PacifiCorp East	PacifiCorp West	NF	7/8	JBSN
289	Phillips 66 Energy Trading LLC	PacifiCorp East	Bonneville Power Administration	NF	7/8	JBSN
290	Phillips 66 Energy Trading LLC	PacifiCorp East	Avista	NF	7/8	JBSN
291	Phillips 66 Energy Trading LLC	PacifiCorp East	Sierra Pacific Power	NF	7/8	JBSN
292	Phillips 66 Energy Trading LLC	PacifiCorp East	PacifiCorp East	SFP	7/8	JEFF
293	Phillips 66 Energy Trading LLC	PacifiCorp East	Avista	SFP	7/8	JEFF
294	Phillips 66 Energy Trading LLC	PacifiCorp East	Sierra Pacific Power	NF	7/8	JEFF
295	Phillips 66 Energy Trading LLC	PacifiCorp East	Sierra Pacific Power	SFP	7/8	JEFF
296	Phillips 66 Energy Trading LLC	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE
297	Phillips 66 Energy Trading LLC	Avista	Bonneville Power Administration	NF	7/8	LOLO
298	Phillips 66 Energy Trading LLC	Avista	Sierra Pacific Power	NF	7/8	LOLO
299	Phillips 66 Energy Trading LLC	Sierra Pacific Power	NorthWestern/PacifiCorp East	SFP	7/8	M345
300	Phillips 66 Energy Trading LLC	Sierra Pacific Power	NorthWestern/PacifiCorp East	SFP	7/8	M345
301	Phillips 66 Energy Trading LLC	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
302	Phillips 66 Energy Trading LLC	Sierra Pacific Power	PacifiCorp East	SFP	7/8	M345
303	Phillips 66 Energy Trading LLC	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
304	Phillips 66 Energy Trading LLC	Sierra Pacific Power	Bonneville Power Administration	SFP	7/8	M345
305	Phillips 66 Energy Trading LLC	Sierra Pacific Power	Avista	NF	7/8	M345
306	Phillips 66 Energy Trading LLC	Sierra Pacific Power	Avista	SFP	7/8	M345
307	Phillips 66 Energy Trading LLC	Idaho Power Company	PacifiCorp East	NF	7/8	OBBLPR
308	Phillips 66 Energy Trading LLC	Idaho Power Company	PacifiCorp East	SFP	7/8	OBBLPR
309	Phillips 66 Energy Trading LLC	Idaho Power Company	Sierra Pacific Power	SFP	7/8	OBBLPR
310	Phillips 66 Energy Trading LLC	Idaho Power Company	PacifiCorp East	NF	7/8	WALLAWALLA

311	Phillips 66 Energy Trading LLC	Idaho Power Company	Sierra Pacific Power	NF	7/8	WALLAWALLA
312	Phillips 66 Energy Trading LLC	Idaho Power Company	Sierra Pacific Power	SFP	7/8	WALLAWALLA
313	Portland General Electric	PacifiCorp East	Avista	NF	7/8	BORA
314	Portland General Electric	PacifiCorp East	Bonneville Power Administration	NF	7/8	BRDY
315	Portland General Electric	PacifiCorp East	Bonneville Power Administration	NF	7/8	JEFF
316	Portland General Electric	Sierra Pacific Power	PacifiCorp West	NF	7/8	M345
317	Portland General Electric	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
318	Powerex Corp.	PacifiCorp East	PacifiCorp West	NF	7/8	ANTE
319	Powerex Corp.	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	AVAT.NWMT
320	Powerex Corp.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF	7/8	AVAT.NWMT
321	Powerex Corp.	Idaho Power Company	PacifiCorp East	NF	7/8	BGSY
322	Powerex Corp.	Idaho Power Company	PacifiCorp East	SFP	7/8	BGSY
323	Powerex Corp.	PacifiCorp East	PacifiCorp East	NF	7/8	BORA
324	Powerex Corp.	PacifiCorp East	PacifiCorp East	SFP	7/8	BORA
325	Powerex Corp.	PacifiCorp East	NorthWestern/PacifiCorp East	SFP	7/8	BORA
326	Powerex Corp.	PacifiCorp East	PacifiCorp East	NF	7/8	BORA
327	Powerex Corp.	PacifiCorp East	PacifiCorp West	NF	7/8	BORA
328	Powerex Corp.	PacifiCorp East	PacifiCorp West	SFP	7/8	BORA
329	Powerex Corp.	PacifiCorp East	PacifiCorp West	NF	7/8	BORA
330	Powerex Corp.	PacifiCorp East	PacifiCorp West	SFP	7/8	BORA
331	Powerex Corp.	PacifiCorp East	Bonneville Power Administration	NF	7/8	BORA
332	Powerex Corp.	PacifiCorp East	Bonneville Power Administration	SFP	7/8	BORA
333	Powerex Corp.	PacifiCorp East	Avista	NF	7/8	BORA
334	Powerex Corp.	PacifiCorp East	Avista	SFP	7/8	BORA
335	Powerex Corp.	PacifiCorp East	Sierra Pacific Power	NF	7/8	BORA
336	Powerex Corp.	PacifiCorp East	PacifiCorp West	NF	7/8	BORA
337	Powerex Corp.	PacifiCorp East	NorthWestern/PacifiCorp East	NF	7/8	BORA
338	Powerex Corp.	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	BPAT.NWMT
339	Powerex Corp.	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	BPAT.NWMT
340	Powerex Corp.	PacifiCorp East	PacifiCorp East	NF	7/8	BRDY
341	Powerex Corp.	PacifiCorp East	PacifiCorp East	NF	7/8	BRDY
342	Powerex Corp.	PacifiCorp East	PacifiCorp West	NF	7/8	BRDY
343	Powerex Corp.	PacifiCorp East	PacifiCorp West	NF	7/8	BRDY
344	Powerex Corp.	PacifiCorp East	PacifiCorp East	NF	7/8	BRDY
345	Powerex Corp.	PacifiCorp East	Bonneville Power Administration	NF	7/8	BRDY

346	Powerex Corp.	PacifiCorp East	Avista	NF	7/8	BRDY
347	Powerex Corp.	PacifiCor E	Avista	SFP	7/8	BRDY
348	Powerex Corp.	PacifiCorp East	NorthWestern/PacifiCorp East	NF	7/8	BRDY
349	Powerex Corp.	PacifiCorp East	NorthWestern/PacifiCorp East	SFP	7/8	GSHN
350	Powerex Corp.	PacifiCorp East	PacifiCorp West	NF	7/8	GSHN
351	Powerex Corp.	PacifiCorp East	PacifiCorp West	SFP	7/8	GSHN
352	Powerex Corp.	PacifiCorp East	PacifiCorp West	NF	7/8	GSHN
353	Powerex Corp.	PacifiCorp East	PacifiCorp West	SFP	7/8	GSHN
354	Powerex Corp.	PacifiCorp East	Bonneville Power Administration	NF	7/8	GSHN
355	Powerex Corp.	PacifiCorp East	Bonneville Power Administration	SFP	7/8	GSHN
356	Powerex Corp.	PacifiCorp East	Avista	NF	7/8	GSHN
357	Powerex Corp.	PacifiCorp East	Avista	SFP	7/8	GSHN
358	Powerex Corp.	PacifiCorp East	NorthWestern/PacifiCorp East	NF	7/8	GSHN
359	Powerex Corp.	PacifiCorp West	PacifiCorp East	NF	7/8	H500
360	Powerex Corp.	PacifiCorp West	Sierra Pacific Power	NF	7/8	H500
361	Powerex Corp.	PacifiCorp West	PacifiCorp East	NF	7/8	HURR
362	Powerex Corp.	PacifiCorp West	Avista	NF	7/8	HURR
363	Powerex Corp.	PacifiCorp West	Sierra Pacific Power	NF	7/8	HURR
364	Powerex Corp.	PacifiCorp East	PacifiCorp East	NF	7/8	JBSN
365	Powerex Corp.	PacifiCorp East	PacifiCorp East	NF	7/8	JBSN
366	Powerex Corp.	PacifiCorp East	PacifiCorp East	NF	7/8	JBSN
367	Powerex Corp.	PacifiCorp East	PacifiCorp East	NF	7/8	JBSN
368	Powerex Corp.	PacifiCorp East	PacifiCorp West	NF	7/8	JBSN
369	Powerex Corp.	PacifiCorp East	PacifiCorp West	NF	7/8	JBSN
370	Powerex Corp.	PacifiCorp East	Bonneville Power Administration	NF	7/8	JBSN
371	Powerex Corp.	PacifiCorp East	Avista	NF	7/8	JBSN
372	Powerex Corp.	PacifiCorp East	Sierra Pacific Power	NF	7/8	JBSN
373	Powerex Corp.	PacifiCorp East	PacifiCorp West	NF	7/8	JBSN
374	Powerex Corp.	PacifiCorp East	NorthWestern/PacifiCorp East	NF	7/8	JBSN
375	Powerex Corp.	PacifiCorp East	PacifiCorp East	NF	7/8	JEFF
376	Powerex Corp.	PacifiCorp East	Avista	NF	7/8	JEFF
377	Powerex Corp.	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
378	Powerex Corp.	Bonneville Power Administration	PacifiCorp East	SFP	7/8	LAGRANDE
379	Powerex Corp.	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
380	Powerex Corp.	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
381	Powerex Corp.	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE

382	Powerex Corp.	Avista	PacifiCorp East	NF	7/8	LOLO
383	Powerex Corp.	Avista	PacifiCorp East	SFP	7/8	LOLO
384	Powerex Corp.	Avista	PacifiCorp West	NF	7/8	LOLO
385	Powerex Corp.	Avista	PacifiCorp East	SFP	7/8	LOLO
386	Powerex Corp.	Avista	Sierra Pacific Power	NF	7/8	LOLO
387	Powerex Corp.	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
388	Powerex Corp.	Sie4r	PacifiCorp East	SFP	7/8	M345
389	Powerex Corp.	Sierra Pacific Power	NorthWestern/PacifiCorp East	SFP	7/8	M345
390	Powerex Corp.	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
391	Powerex Corp.	Sierra Pacific Power	PacifiCorp East	SFP	7/8	M345
392	Powerex Corp.	Sierra Pacific Power	PacifiCorp West	NF	7/8	M345
393	Powerex Corp.	Sierra Pacific Power	PacifiCorp West	SFP	7/8	M345
394	Powerex Corp.	Sierra Pacific Power	PacifiCorp West	NF	7/8	M345
395	Powerex Corp.	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
396	Powerex Corp.	Sierra Pacific Power	Bonneville Power Administration	SFP	7/8	M345
397	Powerex Corp.	Sierra Pacific Power	Avista	NF	7/8	M345
398	Powerex Corp.	Sierra Pacific Power	Avista	SFP	7/8	M345
399	Powerex Corp.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF	7/8	M345
400	Powerex Corp.	PacifiCorp West	PacifiCorp East	NF	7/8	M500
401	Powerex Corp.	NorthWestern/PacifiCorp East	NorthWestern/PacifiCorp East	SFP	7/8	MLCK
402	Powerex Corp.	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	MLCK
403	Powerex Corp.	NorthWestern/PacifiCorp East	NorthWestern/PacifiCorp East	SFP	7/8	MLCK
404	Powerex Corp.	NorthWestern/PacifiCorp East	Avista	NF	7/8	MLCK
405	Powerex Corp.	PacifiCorp West	PacifiCorp East	NF	7/8	SMLK
406	Powerex Corp.	PacifiCorp West	PacifiCorp East	SFP	7/8	SMLK
407	Powerex Corp.	PacifiCorp West	PacifiCorp East	NF	7/8	SMLK
408	Powerex Corp.	PacifiCorp West	Sierra Pacific Power	NF	7/8	SMLK
409	Powerex Corp.	Idaho Power Company	PacifiCorp East	NF	7/8	WALLAWALLA
410	Powerex Corp.	Idaho Power Company	PacifiCorp East	SFP	7/8	WALLAWALLA
411	Powerex Corp.	Idaho Power Company	PacifiCorp East	SFP	7/8	WALLAWALLA
412	Prospector Windfarm, LLC			NF	11	
413	Puget Sound Energy	Idaho Power Company	PacifiCorp East	NF	7/8	BGSY
414	Puget Sound Energy	PacifiCorp East	Bonneville Power Administration	NF	7/8	BORA
415	Puget Sound Energy	PacifiCorp East	Bonneville Power Administration	NF	7/8	BRDY
416	Puget Sound Energy	PacifiCorp East	PacifiCorp East	NF	7/8	JEFF
417	Puget Sound Energy	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE
418	Puget Sound Energy	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345

419	Puget Sound Energy	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
420	Rainbow Energy Marketing Corporation	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF	7/8	AVAT.NWMT
421	Rainbow Energy Marketing Corporation	Idaho Power Company	PacifiCorp East	NF	7/8	BGSY
422	Rainbow Energy Marketing Corporation	Idaho Power Company	PacifiCorp East	SFP	7/8	BGSY
423	Rainbow Energy Marketing Corporation	Idaho Power Company	NorthWestern/PacifiCorp East	NF	7/8	BGSY
424	Rainbow Energy Marketing Corporation	PacifiCorp East	Bonneville Power Administration	NF	7/8	BORA
425	Rainbow Energy Marketing Corporation	PacifiCorp East	Sierra Pacific Power	NF	7/8	BORA
426	Rainbow Energy Marketing Corporation	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF	7/8	BPAT.NWMT
427	Rainbow Energy Marketing Corporation	PacifiCorp West	Sierra Pacific Power	NF	7/8	HURR
428	Rainbow Energy Marketing Corporation	PacifiCorp East	PacifiCorp East	NF	7/8	JBSN
429	Rainbow Energy Marketing Corporation	PacifiCorp East	Bonneville Power Administration	NF	7/8	JBSN
430	Rainbow Energy Marketing Corporation	PacifiCorp East	Sierra Pacific Power	NF	7/8	JBSN
431	Rainbow Energy Marketing Corporation	PacifiCorp East	PacifiCorp East	SFP	7/8	JEFF
432	Rainbow Energy Marketing Corporation	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE
433	Rainbow Energy Marketing Corporation	Avista	PacifiCorp East	NF	7/8	LOLO
434	Rainbow Energy Marketing Corporation	Avista	Sierra Pacific Power	NF	7/8	LOLO
435	Rainbow Energy Marketing Corporation	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
436	Rainbow Energy Marketing Corporation	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
437	Rainbow Energy Marketing Corporation	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
438	Rainbow Energy Marketing Corporation	Idaho Power Company	PacifiCorp East	NF	7/8	OBBLPR
439	Rainbow Energy Marketing Corporation	Idaho Power Company	Sierra Pacific Power	NF	7/8	WALLAWALLA
440	Riley Solar I	Bonneville Power Administration	Bonneville Power Administration	NF	7/8	LAGRANDE
441	Rockland Wind Farm, LLC			NF	11	
442	Seattle City Light	PacifiCorp East	Bonneville Power Administration	NF	7/8	BRDY
443	Seattle City Light	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE
444	Seattle City Light	Idaho Power Company	PacifiCorp East	NF	7/8	LYPK
445	Seattle City Light	Idaho Power Company	PacifiCorp East	NF	7/8	LYPK
446	Seattle City Light	Idaho Power Company	PacifiCorp East	SFP	7/8	LYPK

447	Seattle City Light	Idaho Power Company	Sierra Pacific Power	NF	7/8	LYPK
448	Seattle City Light	Idaho Power Company	Sierra Pacific Power	SFP	7/8	LYPK
449	Seattle City Light	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
450	Shell Energy North America (US), L.P.	PacifiCorp East	PacifiCorp West	NF	7/8	BORA
451	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	NF	7/8	BORA
452	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	SFP	7/8	BORA
453	Shell Energy North America (US), L.P.	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	BPAT.NWMT
454	Shell Energy North America (US), L.P.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF	7/8	BPAT.NWMT
455	Shell Energy North America (US), L.P.	PacifiCorp East	PacifiCorp East	NF	7/8	BRDY
456	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	NF	7/8	BRDY
457	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	NF	7/8	BRDY
458	Shell Energy North America (US), L.P.	PacifiCorp West	PacifiCorp East	NF	7/8	HURR
459	Shell Energy North America (US), L.P.	PacifiCorp West	Bonneville Power Administration	NF	7/8	HURR
460	Shell Energy North America (US), L.P.	PacifiCorp West	Sierra Pacific Power	NF	7/8	HURR
461	Shell Energy North America (US), L.P.	PacifiCorp East	PacifiCorp East	NF	7/8	JBSN
462	Shell Energy North America (US), L.P.	PacifiCorp East	PacifiCorp West	NF	7/8	JBSN
463	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	NF	7/8	JBSN
464	Shell Energy North America (US), L.P.	PacifiCorp East	PacifiCorp West	NF	7/8	JBSN
465	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
466	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
467	Shell Energy North America (US), L.P.	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE
468	Shell Energy North America (US), L.P.	Avista	Sierra Pacific Power	NF	7/8	LOLO
469	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
470	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp West	NF	7/8	M345
471	Shell Energy North America (US), L.P.	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
472	Shell Energy North America (US), L.P.	Sierra Pacific Power	Bonneville Power Administration	SFP	7/8	M345
473	Shell Energy North America (US), L.P.	PacifiCorp West	PacifiCorp East	NF	7/8	M500
474	Shell Energy North America (US), L.P.	PacifiCorp West	Idaho Power Company	NF	7/8	SMLK

475	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	NF	7/8	WALLAWALLA
476	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	SFP	7/8	WALLAWALLA
477	Shell Energy North America (US), L.P.	Idaho Power Company	Sierra Pacific Power	NF	7/8	WALLAWALLA
478	Starvation Solar I, LLC	Bonneville Power Administration	Bonneville Power Administration	NF	7/8	LAGRANDE
479	Suntex Solar, LLC	Bonneville Power Administration	Bonneville Power Administration	NF	7/8	LAGRANDE
480	TEC Energy Inc.	PacifiCorp East	Sierra Pacific Power	NF	7/8	BRDY
481	TEC Energy Inc.	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
482	Tenaska Power Services	PacifiCorp East	Sierra Pacific Power	NF	7/8	BRDY
483	Tenaska Power Services	PacifiCorp East	Sierra Pacific Power	SFP	7/8	BRDY
484	Tenaska Power Services	PacifiCorp East	Sierra Pacific Power	NF	7/8	GSHN
485	Tenaska Power Services	PacifiCorp East	PacifiCorp East	NF	7/8	JEFF
486	Tenaska Power Services	Idaho Power Company	PacifiCorp East	NF	7/8	MDSK
487	Tenaska Power Services	Idaho Power Company	PacifiCorp East	SFP	7/8	MDSK
488	The Energy Authority, Inc.	PacifiCorp East	Sierra Pacific Power	NF	7/8	ANTE
489	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF	7/8	AVAT.NWMT
490	The Energy Authority, Inc.	PacifiCorp East	PacifiCorp West	NF	7/8	BORA
491	The Energy Authority, Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	BORA
492	The Energy Authority, Inc.	PacifiCorp East	Sierra Pacific Power	NF	7/8	BORA
493	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	BPAT.NWMT
494	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	PacifiCorp West	NF	7/8	BPAT.NWMT
495	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF	7/8	BPAT.NWMT
496	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF	7/8	BPAT.NWMT
497	The Energy Authority, Inc.	PacifiCorp East	PacifiCorp West	NF	7/8	BRDY
498	The Energy Authority, Inc.	PacifiCorp East	PacifiCorp West	NF	7/8	BRDY
499	The Energy Authority, Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	BRDY
500	The Energy Authority, Inc.	PacifiCorp East	Sierra Pacific Power	NF	7/8	BRDY
501	The Energy Authority, Inc.	PacifiCorp West	PacifiCorp East	NF	7/8	HURR
502	The Energy Authority, Inc.	PacifiCorp West	Sierra Pacific Power	NF	7/8	HURR
503	The Energy Authority, Inc.	Idaho Power Company	Bonneville Power Administration	NF	7/8	IPCOGEN
504	The Energy Authority, Inc.	PacifiCorp East	PacifiCorp East	NF	7/8	JBSN
505	The Energy Authority, Inc.	PacifiCorp East	PacifiCorp East	NF	7/8	JBSN
506	The Energy Authority, Inc.	PacifiCorp East	PacifiCorp East	NF	7/8	JBSN
507	The Energy Authority, Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	JBSN
508	The Energy Authority, Inc.	PacifiCorp East	Sierra Pacific Power	NF	7/8	JBSN
509	The Energy Authority, Inc.	PacifiCorp East	PacifiCorp West	NF	7/8	JBSN

510	The Energy Authority, Inc.	PacifiCorp East	PacifiCorp East	NF	7/8	JEFF
511	The Energy Authority, Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	JEFF
512	The Energy Authority, Inc.	PacifiCorp East	Sierra Pacific Power	NF	7/8	JEFF
513	The Energy Authority, Inc.	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
514	The Energy Authority, Inc.	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
515	The Energy Authority, Inc.	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE
516	The Energy Authority, Inc.	Avista	Sierra Pacific Power	NF	7/8	LOLO
517	The Energy Authority, Inc.	Idaho Power Company	Bonneville Power Administration	NF	7/8	LYPK
518	The Energy Authority, Inc.	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
519	The Energy Authority, Inc.	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
520	The Energy Authority, Inc.	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
521	The Energy Authority, Inc.	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
522	The Energy Authority, Inc.	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
523	The Energy Authority, Inc.	PacifiCorp West	PacifiCorp East	NF	7/8	M500
524	The Energy Authority, Inc.	PacifiCorp West	Sierra Pacific Power	NF	7/8	POP
525	The Energy Authority, Inc.	PacifiCorp West	PacifiCorp East	NF	7/8	SMLK
526	The Energy Authority, Inc.	PacifiCorp West	PacifiCorp East	NF	7/8	SMLK
527	TransAlta Energy Marketing (US) Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	SFP	7/8	BORA
528	TransAlta Energy Marketing (US) Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	BORA
529	TransAlta Energy Marketing (US) Inc.	PacifiCorp East	Bonneville Power Administration	SFP	7/8	BORA
530	TransAlta Energy Marketing (US) Inc.	PacifiCorp East	Avista	NF	7/8	BORA
531	TransAlta Energy Marketing (US) Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF	7/8	BPAT.NWMT
532	TransAlta Energy Marketing (US) Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	BRDY
533	TransAlta Energy Marketing (US) Inc.	PacifiCorp East	Sierra Pacific Power	NF	7/8	BRDY
534	TransAlta Energy Marketing (US) Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF	7/8	JBSN
535	TransAlta Energy Marketing (US) Inc.	PacifiCorp East	Bonneville Power Administration	NF	7/8	JBSN
536	TransAlta Energy Marketing (US) Inc.	PacifiCorp East	Sierra Pacific Power	NF	7/8	JEFF
537	TransAlta Energy Marketing (US) Inc.	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
538	TransAlta Energy Marketing (US) Inc.	Bonneville Power Administration	PacifiCorp East	NF	7/8	LAGRANDE
539	TransAlta Energy Marketing (US) Inc.	Bonneville Power Administration	Sierra Pacific Power	NF	7/8	LAGRANDE

540	TransAlta Energy Marketing (US) Inc.	Sierra Pacific Power	PacifiCorp East	NF	7/8	M345
541	TransAlta Energy Marketing (US) Inc.	Sierra Pacific Power	Bonneville Power Administration	NF	7/8	M345
542	TransAlta Energy Marketing (US) Inc.	Sierra Pacific Power	Bonneville Power Administration	SFP	7/8	M345
543	TransAlta Energy Marketing (US) Inc.	Idaho Power Company	PacifiCorp East	NF	7/8	WALLAWALLA
544	Utah Associated Municipal Power Systems	PacifiCorp East	Sierra Pacific Power	NF	7/8	BORA
545	Vitol Inc.	Idaho Power Company	PacifiCorp East	NF	7/8	MDSK
546	West Hines Solar, LLC	Bonneville Power Administration	Bonneville Power Administration	NF	7/8	LAGRANDE
547	West Point RNG LLC	Idaho Power Company	PacifiCorp East	NF	7/8	MDSK
548	West Point RNG LLC	Idaho Power Company	PacifiCorp East	SFP	7/8	MDSK
549	Willow Springs Windfarm, LLC			NF	11	
35	TOTAL					

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	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)
1	^(a) Bonneville Power Administration - OTEC			359,335	359,335	1,971,867
2	^(b) Bonneville Power Administration - USBR			191,599	191,599	1,447,951
3	^(c) Bonneville Power Administration - PF			1,488,515	1,488,515	7,464,517
4	^(d) Milner Irrigation District	Various in Idaho		10,759	10,759	
5	Seattle City Light			311,138	311,138	
6	^(e) PacifiCorp			2,088	2,088	12,404
7	^(f) United States Bureau of Indian Affairs	Various in Idaho		18,109	18,109	
8	AmpRenew Offtake I LLC			0	0	
9	West Point RNG LLC			0	0	
10	AmpRenew Offtake I LLC	M345		8,991	8,991	
11	Bonneville Power Administration	KPRT		90,359	90,359	
12	Bonneville Power Administration	KPRT		517,773	517,773	
13	Energy Keepers, Inc.	M345		126,023	126,023	

14	Mercuria Energy America, LLC	M345		160	160	
15	PacifiCorp Inc.	HURR		1,792,411	1,792,411	
16	PacifiCorp Inc.	LAGRANDE		802,450	802,450	
17	PacifiCorp Inc.	HURR		579,682	579,682	
18	Powerex Corporation	BORA		43,607	43,607	
19	Seattle City Light	LAGRANDE		244,673	244,673	
20	West Point RNG LLC	M345		15,895	15,895	
21	Adapture Renewables, Inc. (Morgan Solar)			0	0	
22	Adapture Renewables, Inc. (Ontario Solar Center)			0	0	
23	Adapture Renewables, Inc. (Vale I Solar)			0	0	
24	Altop Energy Trading, LLC	HURR		1,254	1,254	
25	Altop Energy Trading, LLC	LAGRANDE		1,457	1,457	
26	Altop Energy Trading, LLC	LOLO		1,266	1,266	
27	Altop Energy Trading, LLC	LAGRANDE		316	316	
28	Altop Energy Trading, LLC	LOLO		10	10	
29	Altop Energy Trading, LLC	M345		200	200	
30	Altop Energy Trading, LLC	JBSN		91	91	
31	Altop Energy Trading, LLC	LOLO		887	887	
32	Altop Energy Trading, LLC	BORA		290	290	
33	Altop Energy Trading, LLC	M345		3,837	3,837	
34	Altop Energy Trading, LLC	M345		781	781	
35	Altop Energy Trading, LLC	HURR		140	140	
36	Altop Energy Trading, LLC	HURR		128	128	
37	Altop Energy Trading, LLC	IPCO		25	25	
38	Altop Energy Trading, LLC	JBSN		175	175	
39	Altop Energy Trading, LLC	LAGRANDE		2,386	2,386	
40	Altop Energy Trading, LLC	LAGRANDE		137	137	
41	Altop Energy Trading, LLC	LOLO		220	220	
42	Altop Energy Trading, LLC	BORA		207	207	
43	Altop Energy Trading, LLC	M345		800	800	
44	Arizona Public Service			0	0	
45	Avangrid Renewables, LLC	HURR		75	75	
46	Avangrid Renewables, LLC	LAGRANDE		1,467	1,467	
47	Avangrid Renewables, LLC	LOLO		150	150	
48	Avangrid Renewables, LLC	LAGRANDE		2,145	2,145	
49	Avangrid Renewables, LLC	LAGRANDE		12,146	12,146	
50	Avangrid Renewables, LLC	BORA		50	50	
51	Avista Corporation	LOLO		597	597	

52	Benson Creek Windfarm, LLC			0	0
53	Bonneville Power Administration	ANTE		498	498
54	Bonneville Power Administration	BORA		183	183
55	Bonneville Power Administration	M345		4	4
56	Bonneville Power Administration	GSHN		150	150
57	Bonneville Power Administration	BORA		315	315
58	Bonneville Power Administration	KPRT		2,340	2,340
59	Bonneville Power Administration	KPRT		40,378	40,378
60	Bonneville Power Administration	LAGRANDE		1,022	1,022
61	Bonneville Power Administration	LAGRANDE		3,395	3,395
62	Bonneville Power Administration	M345		64,171	64,171
63	Bonneville Power Administration	M345		2,671	2,671
64	Bonneville Power Administration	BORA		337	337
65	Bonneville Power Administration	BORA		35	35
66	Bonneville Power Administration	BRDY		6	6
67	Bonneville Power Administration	KPRT		29	29
68	Bonneville Power Administration	LAGRANDE		332	332
69	Bonneville Power Administration	BORA		155	155
70	Bonneville Power Administration	M345		25	25
71	Brookfield Renewable Trading & Marketing			0	0
72	CP Energy Marketing (US) Inc.	JBSN		150	150
73	Durbin Creek Windfarm, LLC			0	0
74	Dynasty Power Inc.	LAGRANDE		1,780	1,780
75	Dynasty Power Inc.	LOLO		816	816
76	Dynasty Power Inc.	LOLO		1,600	1,600
77	Dynasty Power Inc.	BRDY		65	65
78	Dynasty Power Inc.	LOLO		1	1
79	Dynasty Power Inc.	M345		324	324
80	Dynasty Power Inc.	LAGRANDE		100	100
81	Dynasty Power Inc.	LOLO		460	460

82	Dynasty Power Inc.	M345		289	289
83	Dynasty Power Inc.	H500		8,180	8,180
84	Dynasty Power Inc.	HURR		5	5
85	Dynasty Power Inc.	LAGRANDE		196	196
86	Dynasty Power Inc.	LOLO		580	580
87	Dynasty Power Inc.	H500		33	33
88	Dynasty Power Inc.	LAGRANDE		2,869	2,869
89	Dynasty Power Inc.	LOLO		601	601
90	Dynasty Power Inc.	M345		297	297
91	Dynasty Power Inc.	LOLO		50	50
92	Dynasty Power Inc.	M345		3,677	3,677
93	Dynasty Power Inc.	M345		1,930	1,930
94	Dynasty Power Inc.	BORA		55	55
95	Dynasty Power Inc.	BRDY		476	476
96	Dynasty Power Inc.	HURR		180	180
97	Dynasty Power Inc.	LAGRANDE		51,078	51,078
98	Dynasty Power Inc.	LOLO		3,031	3,031
99	Dynasty Power Inc.	LOLO		2,885	2,885
100	Dynasty Power Inc.	BORA		253	253
101	EDF Trading North America, LLC	GSHN		46	46
102	EDF Trading North America, LLC	M345		5	5
103	EDF Trading North America, LLC	BRDY		5	5
104	Energy Keepers, Inc.	JEFF		88	88
105	Energy Keepers, Inc.	JEFF		1,578	1,578
106	Energy Keepers, Inc.	AVAT.NWMT		160	160
107	Energy Keepers, Inc.	JBSN		2,622	2,622
108	Energy Keepers, Inc.	JBSN		528	528
109	Energy Keepers, Inc.	LAGRANDE		4,040	4,040
110	Energy Keepers, Inc.	LOLO		688	688
111	Energy Keepers, Inc.	M345		23	23
112	Energy Keepers, Inc.	BRDY		57	57
113	Energy Keepers, Inc.	LOLO		400	400
114	Energy Keepers, Inc.	BGSY		28	28
115	Energy Keepers, Inc.	BRDY		119	119
116	Energy Keepers, Inc.	BRDY		243	243
117	Energy Keepers, Inc.	JBSN		1,904	1,904
118	Energy Keepers, Inc.	LAGRANDE		2,916	2,916
119	Energy Keepers, Inc.	LOLO		283	283

120	Energy Keepers, Inc.	M345		8,729	8,729	
121	Energy Keepers, Inc.	M345		21,319	21,319	
122	Energy Keepers, Inc.	M345		4,110	4,110	
123	Energy Keepers, Inc.	M345		164	164	
124	Energy Keepers, Inc.	M345		1,384	1,384	
125	Energy Keepers, Inc.	M345		680	680	
126	Energy Keepers, Inc.	BRDY		528	528	
127	Energy Keepers, Inc.	BRDY		8,414	8,414	
128	Energy Keepers, Inc.	LAGRANDE		1,275	1,275	
129	Energy Keepers, Inc.	LOLO		1,212	1,212	
130	Guzman Energy Group LLC	BORA		907	907	
131	Guzman Energy Group LLC	M345		57	57	
132	Guzman Energy Group LLC	JEFF		89	89	
133	Guzman Energy Group LLC	HURR		694	694	
134	Guzman Energy Group LLC	LAGRANDE		110	110	
135	Guzman Energy Group LLC	LOLO		165	165	
136	Guzman Energy Group LLC	LOLO		1,748	1,748	
137	Guzman Energy Group LLC	BORA		150	150	
138	Guzman Energy Group LLC	BRDY		213	213	
139	Guzman Energy Group LLC	M345		272	272	
140	Guzman Energy Group LLC	BORA		35	35	
141	Guzman Energy Group LLC	HURR		63	63	
142	Guzman Energy Group LLC	LOLO		110	110	
143	Guzman Energy Group LLC	M345		115	115	
144	Guzman Energy Group LLC	MLCK		112	112	
145	Guzman Energy Group LLC	JBSN		5	5	
146	Guzman Energy Group LLC	M345		56	56	
147	Guzman Energy Group LLC	BORA		610	610	
148	Guzman Energy Group LLC	BORA		231	231	
149	Guzman Energy Group LLC	LAGRANDE		38	38	
150	Guzman Energy Group LLC	LOLO		2,041	2,041	
151	Guzman Energy Group LLC	M345		60	60	
152	Guzman Energy Group LLC	LAGRANDE		32	32	
153	Guzman Energy Group LLC	BORA		486	486	
154	Guzman Energy Group LLC	H500		19	19	
155	Guzman Energy Group LLC	JBSN		612	612	
156	Guzman Energy Group LLC	M345		285	285	
157	Guzman Energy Group LLC	BORA		593	593	
158	Guzman Energy Group LLC	JBSN		1,202	1,202	
159	Guzman Energy Group LLC	M345		535	535	

160	Guzman Energy Group LLC	LAGRANDE		622	622
161	Guzman Energy Group LLC	LOLO		75	75
162	Guzman Energy Group LLC	BORA		105	105
163	Idaho Wind Partners 1, LLC (Pilgrim Stage Station Wind)			0	0
164	Jett Creek Windfarm, LLC			0	0
165	Macquarie Energy, LLC	LAGRANDE		26	26
166	Macquarie Energy, LLC	BRDY		150	150
167	Macquarie Energy, LLC	LAGRANDE		2,619	2,619
168	Macquarie Energy, LLC	LOLO		3	3
169	Macquarie Energy, LLC	LAGRANDE		4,308	4,308
170	Macquarie Energy, LLC	LOLO		291	291
171	Macquarie Energy, LLC	M345		779	779
172	Macquarie Energy, LLC	BRDY		17	17
173	Macquarie Energy, LLC	LAGRANDE		225	225
174	Macquarie Energy, LLC	LOLO		234	234
175	Macquarie Energy, LLC	M345		45	45
176	Macquarie Energy, LLC	M345		345	345
177	Macquarie Energy, LLC	BPAT.NWMT		208	208
178	Macquarie Energy, LLC	M345		786	786
179	Macquarie Energy, LLC	LAGRANDE		155	155
180	Macquarie Energy, LLC	M345		3,966	3,966
181	Macquarie Energy, LLC	AVAT.NWMT		800	800
182	Macquarie Energy, LLC	BPAT.NWMT		2,879	2,879
183	Macquarie Energy, LLC	BRDY		909	909
184	Macquarie Energy, LLC	BRDY		300	300
185	Macquarie Energy, LLC	HURR		400	400
186	Macquarie Energy, LLC	LAGRANDE		19,923	19,923
187	Macquarie Energy, LLC	LAGRANDE		10,398	10,398
188	Macquarie Energy, LLC	LOLO		275	275
189	Macquarie Energy, LLC	LOLO		672	672
190	Mag Energy Solutions	H500		535	535
191	Mag Energy Solutions	HURR		1,200	1,200
192	Mag Energy Solutions	LAGRANDE		592	592
193	Mag Energy Solutions	M345		9	9
194	Mag Energy Solutions	M345		1,032	1,032
195	Mag Energy Solutions	M345		1,440	1,440
196	Mag Energy Solutions	LAGRANDE		26	26
197	Mag Energy Solutions	JBSN		8	8
198	Mag Energy Solutions	LAGRANDE		4,113	4,113

199	Mag Energy Solutions	LAGRANDE		375	375	
200	Mag Energy Solutions	LOLO		176	176	
201	Mag Energy Solutions	LOLO		3,200	3,200	
202	Mercuria Energy America, LLC	HURR		152	152	
203	Mercuria Energy America, LLC	LAGRANDE		146	146	
204	Mercuria Energy America, LLC	BRDY		6,829	6,829	
205	Mercuria Energy America, LLC	H500		28	28	
206	Mercuria Energy America, LLC	H500		13,689	13,689	
207	Mercuria Energy America, LLC	HURR		352	352	
208	Mercuria Energy America, LLC	HURR		6,690	6,690	
209	Mercuria Energy America, LLC	LAGRANDE		31,713	31,713	
210	Mercuria Energy America, LLC	LOLO		115	115	
211	Mercuria Energy America, LLC	LOLO		2,111	2,111	
212	Mercuria Energy America, LLC	BORA		581	581	
213	Mercuria Energy America, LLC	BRDY		163	163	
214	Mercuria Energy America, LLC	LAGRANDE		50	50	
215	MFT Energy US Power LLC	JBSN		1	1	
216	MFT Energy US Power LLC	BRDY		2,111	2,111	
217	Morgan Stanley Capital Group. Inc.	ANTE		2,814	2,814	
218	Morgan Stanley Capital Group. Inc.	BRDY		267	267	
219	Morgan Stanley Capital Group. Inc.	LAGRANDE		1,883	1,883	
220	Morgan Stanley Capital Group. Inc.	M345		1,842	1,842	
221	Morgan Stanley Capital Group. Inc.	M345		697	697	
222	Morgan Stanley Capital Group. Inc.	BRDY		84	84	
223	Morgan Stanley Capital Group. Inc.	H500		13,955	13,955	
224	Morgan Stanley Capital Group. Inc.	LAGRANDE		953	953	
225	Morgan Stanley Capital Group. Inc.	ANTE		949	949	
226	Morgan Stanley Capital Group. Inc.	BRDY		55	55	

227	Morgan Stanley Capital Group. Inc.	LAGRANDE		523	523	
228	Morgan Stanley Capital Group. Inc.	M345		11,303	11,303	
229	Morgan Stanley Capital Group. Inc.	LAGRANDE		46,190	46,190	
230	Morgan Stanley Capital Group. Inc.	LAGRANDE		355	355	
231	Morgan Stanley Capital Group. Inc.	LOLO		183	183	
232	Morgan Stanley Capital Group. Inc.	M345		23,231	23,231	
233	Morgan Stanley Capital Group. Inc.	M345		7,611	7,611	
234	Morgan Stanley Capital Group. Inc.	LAGRANDE		6,532	6,532	
235	Morgan Stanley Capital Group. Inc.	LOLO		2,866	2,866	
236	Morgan Stanley Capital Group. Inc.	M345		344	344	
237	Morgan Stanley Capital Group. Inc.	M345		137	137	
238	Morgan Stanley Capital Group. Inc.	LAGRANDE		7,258	7,258	
239	Morgan Stanley Capital Group. Inc.	LOLO		746	746	
240	Morgan Stanley Capital Group. Inc.	M345		3,261	3,261	
241	Morgan Stanley Capital Group. Inc.	BORA		114	114	
242	Morgan Stanley Capital Group. Inc.	BRDY		141	141	
243	Morgan Stanley Capital Group. Inc.	LAGRANDE		8,713	8,713	
244	Morgan Stanley Capital Group. Inc.	LOLO		247	247	
245	Morgan Stanley Capital Group. Inc.	M345		18,859	18,859	
246	Morgan Stanley Capital Group. Inc.	M345		1,065	1,065	
247	Morgan Stanley Capital Group. Inc.	BORA		320	320	
248	Morgan Stanley Capital Group. Inc.	BRDY		2,788	2,788	
249	Morgan Stanley Capital Group. Inc.	M345		18,210	18,210	
250	Morgan Stanley Capital Group. Inc.	BORA		602	602	
251	Morgan Stanley Capital Group. Inc.	M345		3,049	3,049	
252	Morgan Stanley Capital Group. Inc.	LAGRANDE		400	400	
253	Morgan Stanley Capital Group. Inc.	BRDY		1,326	1,326	

254	Morgan Stanley Capital Group. Inc.	LAGRANDE		539	539	
255	Morgan Stanley Capital Group. Inc.	LOLO		318	318	
256	Morgan Stanley Capital Group. Inc.	BORA		84	84	
257	Morgan Stanley Capital Group. Inc.	M345		233	233	
258	Morgan Stanley Capital Group. Inc.	BORA		668	668	
259	Morgan Stanley Capital Group. Inc.	M345		1,063	1,063	
260	Nevada Power Company d/b/a NV Energy	M345		1,525	1,525	
261	NorthWestern Energy	LAGRANDE		3,590	3,590	
262	PacifiCorp Inc.	LOLO		2,431	2,431	
263	PacifiCorp Inc.	LOLO		757	757	
264	PacifiCorp Inc.	BORA		5,922	5,922	
265	PacifiCorp Inc.	BRDY		2,197	2,197	
266	PacifiCorp Inc.	BRDY		5,022	5,022	
267	PacifiCorp Inc.	LAGRANDE		25,795	25,795	
268	PacifiCorp Inc.	LOLO		254	254	
269	PacifiCorp Inc.	BGSY		3,926	3,926	
270	PacifiCorp Inc.	BGSY		2,673	2,673	
271	PacifiCorp Inc.	BORA		833	833	
272	PacifiCorp Inc.	BRDY		458	458	
273	PacifiCorp Inc.	BRDY		519	519	
274	PacifiCorp Inc.	BRDY		45	45	
275	PacifiCorp Inc.	BORA		81,288	81,288	
276	PacifiCorp Inc.	BRDY		36	36	
277	Phillips 66 Energy Trading LLC	JEFF		3	3	
278	Phillips 66 Energy Trading LLC	M345		426	426	
279	Phillips 66 Energy Trading LLC	AVAT.NWMT		15,903	15,903	
280	Phillips 66 Energy Trading LLC	LAGRANDE		348	348	
281	Phillips 66 Energy Trading LLC	LAGRANDE		2,472	2,472	
282	Phillips 66 Energy Trading LLC	LOLO		11,046	11,046	
283	Phillips 66 Energy Trading LLC	LOLO		1,306	1,306	
284	Phillips 66 Energy Trading LLC	M345		57,813	57,813	
285	Phillips 66 Energy Trading LLC	M345		1,566	1,566	

286	Phillips 66 Energy Trading LLC	BRDY		400	400	
287	Phillips 66 Energy Trading LLC	BRDY		623	623	
288	Phillips 66 Energy Trading LLC	HURR		2,068	2,068	
289	Phillips 66 Energy Trading LLC	LAGRANDE		32	32	
290	Phillips 66 Energy Trading LLC	LOLO		3,624	3,624	
291	Phillips 66 Energy Trading LLC	M345		1,013	1,013	
292	Phillips 66 Energy Trading LLC	BRDY		1,900	1,900	
293	Phillips 66 Energy Trading LLC	LOLO		2,967	2,967	
294	Phillips 66 Energy Trading LLC	M345		175	175	
295	Phillips 66 Energy Trading LLC	M345		60,488	60,488	
296	Phillips 66 Energy Trading LLC	M345		200	200	
297	Phillips 66 Energy Trading LLC	LAGRANDE		174	174	
298	Phillips 66 Energy Trading LLC	M345		150	150	
299	Phillips 66 Energy Trading LLC	AVAT.NWMT		1,461	1,461	
300	Phillips 66 Energy Trading LLC	BPAT.NWMT		128	128	
301	Phillips 66 Energy Trading LLC	BRDY		586	586	
302	Phillips 66 Energy Trading LLC	BRDY		19,546	19,546	
303	Phillips 66 Energy Trading LLC	LAGRANDE		1,282	1,282	
304	Phillips 66 Energy Trading LLC	LAGRANDE		17,066	17,066	
305	Phillips 66 Energy Trading LLC	LOLO		1,154	1,154	
306	Phillips 66 Energy Trading LLC	LOLO		217,316	217,316	
307	Phillips 66 Energy Trading LLC	BRDY		100	100	
308	Phillips 66 Energy Trading LLC	BRDY		7,222	7,222	
309	Phillips 66 Energy Trading LLC	M345		7,228	7,228	
310	Phillips 66 Energy Trading LLC	BRDY		3,050	3,050	
311	Phillips 66 Energy Trading LLC	M345		18,236	18,236	
312	Phillips 66 Energy Trading LLC	M345		12,011	12,011	

313	Portland General Electric	LOLO		293	293	
314	Portland General Electric	LAGRANDE		2,233	2,233	
315	Portland General Electric	LAGRANDE		645	645	
316	Portland General Electric	HURR		25	25	
317	Portland General Electric	LAGRANDE		943	943	
318	Powerex Corp.	HURR		5	5	
319	Powerex Corp.	ANTE		22	22	
320	Powerex Corp.	LAGRANDE		353	353	
321	Powerex Corp.	JEFF		6,840	6,840	
322	Powerex Corp.	JEFF		1,635	1,635	
323	Powerex Corp.	ANTE		291	291	
324	Powerex Corp.	ANTE		90	90	
325	Powerex Corp.	BPAT.NWMT		751	751	
326	Powerex Corp.	BRDY		124	124	
327	Powerex Corp.	H500		2,830	2,830	
328	Powerex Corp.	H500		1,569	1,569	
329	Powerex Corp.	HURR		2,766	2,766	
330	Powerex Corp.	HURR		533	533	
331	Powerex Corp.	LAGRANDE		12,243	12,243	
332	Powerex Corp.	LAGRANDE		1,450	1,450	
333	Powerex Corp.	LOLO		12,820	12,820	
334	Powerex Corp.	LOLO		9,151	9,151	
335	Powerex Corp.	M345		456	456	
336	Powerex Corp.	M500		258	258	
337	Powerex Corp.	MLCK		242	242	
338	Powerex Corp.	BORA		130	130	
339	Powerex Corp.	JBSN		260	260	
340	Powerex Corp.	ANTE		200	200	
341	Powerex Corp.	GSHN		300	300	
342	Powerex Corp.	H500		1,478	1,478	
343	Powerex Corp.	HURR		934	934	
344	Powerex Corp.	JBSN		20	20	
345	Powerex Corp.	LAGRANDE		2,518	2,518	
346	Powerex Corp.	LOLO		2,968	2,968	
347	Powerex Corp.	LOLO		194	194	
348	Powerex Corp.	MLCK		544	544	
349	Powerex Corp.	BPAT.NWMT		4,572	4,572	
350	Powerex Corp.	H500		593	593	
351	Powerex Corp.	H500		3,493	3,493	
352	Powerex Corp.	HURR		264	264	

353	Powerex Corp.	HURR		1,719	1,719	
354	Powerex Corp.	LAGRANDE		1,142	1,142	
355	Powerex Corp.	LAGRANDE		1,855	1,855	
356	Powerex Corp.	LOLO		382	382	
357	Powerex Corp.	LOLO		1,560	1,560	
358	Powerex Corp.	MLCK		2,551	2,551	
359	Powerex Corp.	GSHN		6	6	
360	Powerex Corp.	M345		104	104	
361	Powerex Corp.	BORA		3,799	3,799	
362	Powerex Corp.	LOLO		25	25	
363	Powerex Corp.	M345		546	546	
364	Powerex Corp.	ANTE		6,034	6,034	
365	Powerex Corp.	BORA		824	824	
366	Powerex Corp.	BRDY		602	602	
367	Powerex Corp.	GSHN		92	92	
368	Powerex Corp.	H500		6,929	6,929	
369	Powerex Corp.	HURR		4,853	4,853	
370	Powerex Corp.	LAGRANDE		62,548	62,548	
371	Powerex Corp.	LOLO		10,461	10,461	
372	Powerex Corp.	M345		27	27	
373	Powerex Corp.	M500		50	50	
374	Powerex Corp.	MLCK		5,832	5,832	
375	Powerex Corp.	GSHN		104	104	
376	Powerex Corp.	LOLO		248	248	
377	Powerex Corp.	BORA		21,752	21,752	
378	Powerex Corp.	BORA		3,654	3,654	
379	Powerex Corp.	BRDY		272	272	
380	Powerex Corp.	JBSN		668	668	
381	Powerex Corp.	M345		1,639	1,639	
382	Powerex Corp.	BRDY		186	186	
383	Powerex Corp.	BRDY		10,936	10,936	
384	Powerex Corp.	HURR		43	43	
385	Powerex Corp.	JBSN		576	576	
386	Powerex Corp.	M345		1,442	1,442	
387	Powerex Corp.	ANTE		107	107	
388	Powerex Corp.	ANTE		470	470	
389	Powerex Corp.	BPAT.NWMT		673	673	
390	Powerex Corp.	GSHN		36	36	
391	Powerex Corp.	GSHN		1,629	1,629	
392	Powerex Corp.	H500		721	721	

393	Powerex Corp.	H500		957	957	
394	Powerex Corp.	HURR		358	358	
395	Powerex Corp.	LAGRANDE		6,501	6,501	
396	Powerex Corp.	LAGRANDE		1,791	1,791	
397	Powerex Corp.	LOLO		2,126	2,126	
398	Powerex Corp.	LOLO		11,569	11,569	
399	Powerex Corp.	MLCK		117	117	
400	Powerex Corp.	BORA		47	47	
401	Powerex Corp.	AVAT.NWMT		95	95	
402	Powerex Corp.	BORA		61	61	
403	Powerex Corp.	BPAT.NWMT		11,798	11,798	
404	Powerex Corp.	LOLO		11	11	
405	Powerex Corp.	BORA		722	722	
406	Powerex Corp.	BORA		794	794	
407	Powerex Corp.	BRDY		200	200	
408	Powerex Corp.	M345		252	252	
409	Powerex Corp.	BORA		634	634	
410	Powerex Corp.	BORA		451	451	
411	Powerex Corp.	JBSN		336	336	
412	Prospector Windfarm, LLC			0	0	
413	Puget Sound Energy	JEFF		2	2	
414	Puget Sound Energy	LAGRANDE		839	839	
415	Puget Sound Energy	LAGRANDE		64	64	
416	Puget Sound Energy	BRDY		35	35	
417	Puget Sound Energy	M345		170	170	
418	Puget Sound Energy	BRDY		812	812	
419	Puget Sound Energy	LAGRANDE		9,018	9,018	
420	Rainbow Energy Marketing Corporation	M345		200	200	
421	Rainbow Energy Marketing Corporation	JEFF		1,425	1,425	
422	Rainbow Energy Marketing Corporation	JEFF		266	266	
423	Rainbow Energy Marketing Corporation	MLCK		152	152	
424	Rainbow Energy Marketing Corporation	LAGRANDE		300	300	
425	Rainbow Energy Marketing Corporation	M345		68	68	
426	Rainbow Energy Marketing Corporation	M345		72	72	
427	Rainbow Energy Marketing Corporation	M345		111	111	

428	Rainbow Energy Marketing Corporation	GSHN		668	668	
429	Rainbow Energy Marketing Corporation	LAGRANDE		655	655	
430	Rainbow Energy Marketing Corporation	M345		481	481	
431	Rainbow Energy Marketing Corporation	BRDY		600	600	
432	Rainbow Energy Marketing Corporation	M345		1,090	1,090	
433	Rainbow Energy Marketing Corporation	BORA		4,963	4,963	
434	Rainbow Energy Marketing Corporation	M345		4,473	4,473	
435	Rainbow Energy Marketing Corporation	BORA		284	284	
436	Rainbow Energy Marketing Corporation	BRDY		17	17	
437	Rainbow Energy Marketing Corporation	LAGRANDE		300	300	
438	Rainbow Energy Marketing Corporation	BRDY		12	12	
439	Rainbow Energy Marketing Corporation	M345		800	800	
440	Riley Solar I	LAGRANDE		278	278	
441	Rockland Wind Farm, LLC			0	0	
442	Seattle City Light	LAGRANDE		523	523	
443	Seattle City Light	M345		3,183	3,183	
444	Seattle City Light	BORA		1,600	1,600	
445	Seattle City Light	JBSN		1,120	1,120	
446	Seattle City Light	JBSN		1,600	1,600	
447	Seattle City Light	M345		55,055	55,055	
448	Seattle City Light	M345		4,800	4,800	
449	Seattle City Light	LAGRANDE		424	424	
450	Shell Energy North America (US), L.P.	HURR		303	303	
451	Shell Energy North America (US), L.P.	LAGRANDE		499	499	
452	Shell Energy North America (US), L.P.	LAGRANDE		1,015	1,015	
453	Shell Energy North America (US), L.P.	JBSN		50	50	
454	Shell Energy North America (US), L.P.	M345		34	34	
455	Shell Energy North America (US), L.P.	BORA		75	75	
456	Shell Energy North America (US), L.P.	LAGRANDE		1,060	1,060	
457	Shell Energy North America (US), L.P.	M345		237	237	

458	Shell Energy North America (US), L.P.	BORA		566	566	
459	Shell Energy North America (US), L.P.	LAGRANDE		321	321	
460	Shell Energy North America (US), L.P.	M345		654	654	
461	Shell Energy North America (US), L.P.	BRDY		93	93	
462	Shell Energy North America (US), L.P.	HURR		6	6	
463	Shell Energy North America (US), L.P.	LAGRANDE		659	659	
464	Shell Energy North America (US), L.P.	M500		69	69	
465	Shell Energy North America (US), L.P.	BORA		736	736	
466	Shell Energy North America (US), L.P.	BRDY		569	569	
467	Shell Energy North America (US), L.P.	M345		2,035	2,035	
468	Shell Energy North America (US), L.P.	M345		61	61	
469	Shell Energy North America (US), L.P.	BORA		70	70	
470	Shell Energy North America (US), L.P.	HURR		67	67	
471	Shell Energy North America (US), L.P.	LAGRANDE		958	958	
472	Shell Energy North America (US), L.P.	LAGRANDE		1,687	1,687	
473	Shell Energy North America (US), L.P.	BRDY		10	10	
474	Shell Energy North America (US), L.P.	IPCO		498	498	
475	Shell Energy North America (US), L.P.	BORA		67	67	
476	Shell Energy North America (US), L.P.	BRDY		304	304	
477	Shell Energy North America (US), L.P.	M345		152	152	
478	Starvation Solar I, LLC	LAGRANDE		562	562	
479	Suntex Solar, LLC	LAGRANDE		129	129	
480	TEC Energy Inc.	M345		49	49	
481	TEC Energy Inc.	BRDY		537	537	
482	Tenaska Power Services	M345		386	386	
483	Tenaska Power Services	M345		6,913	6,913	
484	Tenaska Power Services	M345		33	33	
485	Tenaska Power Services	BRDY		68	68	
486	Tenaska Power Services	GSHN		79	79	
487	Tenaska Power Services	GSHN		24	24	

488	The Energy Authority, Inc.	M345		90	90
489	The Energy Authority, Inc.	M345		254	254
490	The Energy Authority, Inc.	HURR		496	496
491	The Energy Authority, Inc.	LAGRANDE		2,486	2,486
492	The Energy Authority, Inc.	M345		919	919
493	The Energy Authority, Inc.	BRDY		50	50
494	The Energy Authority, Inc.	H500		25	25
495	The Energy Authority, Inc.	JBSN		25	25
496	The Energy Authority, Inc.	M345		3,953	3,953
497	The Energy Authority, Inc.	H500		105	105
498	The Energy Authority, Inc.	HURR		20	20
499	The Energy Authority, Inc.	LAGRANDE		3,827	3,827
500	The Energy Authority, Inc.	M345		1,583	1,583
501	The Energy Authority, Inc.	JBSN		78	78
502	The Energy Authority, Inc.	M345		100	100
503	The Energy Authority, Inc.	LAGRANDE		100	100
504	The Energy Authority, Inc.	BORA		220	220
505	The Energy Authority, Inc.	BRDY		100	100
506	The Energy Authority, Inc.	GSHN		140	140
507	The Energy Authority, Inc.	LAGRANDE		400	400
508	The Energy Authority, Inc.	M345		2,558	2,558
509	The Energy Authority, Inc.	POP		837	837
510	The Energy Authority, Inc.	BRDY		86	86
511	The Energy Authority, Inc.	LAGRANDE		725	725
512	The Energy Authority, Inc.	M345		4,727	4,727
513	The Energy Authority, Inc.	BORA		2,757	2,757
514	The Energy Authority, Inc.	BRDY		600	600
515	The Energy Authority, Inc.	M345		39,231	39,231
516	The Energy Authority, Inc.	M345		1,392	1,392
517	The Energy Authority, Inc.	LAGRANDE		150	150
518	The Energy Authority, Inc.	ANTE		75	75
519	The Energy Authority, Inc.	BORA		81	81
520	The Energy Authority, Inc.	BRDY		310	310
521	The Energy Authority, Inc.	JBSN		369	369
522	The Energy Authority, Inc.	LAGRANDE		10,616	10,616
523	The Energy Authority, Inc.	BORA		197	197
524	The Energy Authority, Inc.	M345		19	19
525	The Energy Authority, Inc.	BORA		281	281
526	The Energy Authority, Inc.	JBSN		95	95

527	TransAlta Energy Marketing (US) Inc.	BPAT.NWMT		681	681	
528	TransAlta Energy Marketing (US) Inc.	LAGRANDE		1,746	1,746	
529	TransAlta Energy Marketing (US) Inc.	LAGRANDE		16,287	16,287	
530	TransAlta Energy Marketing (US) Inc.	LOLO		60	60	
531	TransAlta Energy Marketing (US) Inc.	LAGRANDE		70	70	
532	TransAlta Energy Marketing (US) Inc.	LAGRANDE		1,771	1,771	
533	TransAlta Energy Marketing (US) Inc.	M345		268	268	
534	TransAlta Energy Marketing (US) Inc.	BPAT.NWMT		130	130	
535	TransAlta Energy Marketing (US) Inc.	LAGRANDE		2,544	2,544	
536	TransAlta Energy Marketing (US) Inc.	M345		97	97	
537	TransAlta Energy Marketing (US) Inc.	BORA		3,162	3,162	
538	TransAlta Energy Marketing (US) Inc.	JBSN		88	88	
539	TransAlta Energy Marketing (US) Inc.	M345		2,999	2,999	
540	TransAlta Energy Marketing (US) Inc.	BRDY		206	206	
541	TransAlta Energy Marketing (US) Inc.	LAGRANDE		21,234	21,234	
542	TransAlta Energy Marketing (US) Inc.	LAGRANDE		1,626	1,626	
543	TransAlta Energy Marketing (US) Inc.	BORA		216	216	
544	Utah Associated Municipal Power Systems	M345		11,588	11,588	
545	Vitol Inc.	BORA		10	10	
546	West Hines Solar, LLC	LAGRANDE		612	612	
547	West Point RNG LLC	BORA		124	124	
548	West Point RNG LLC	BORA		1,171	1,171	
549	Willow Springs Windfarm, LLC			0	0	
35	TOTAL			8,375,904	8,375,904	10,896,739

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 Charges (\$) (l)	Other Charges (\$) (m)	Total Revenues (\$) (k+l+m) (n)
1	^(g) Bonneville Power Administration - OTEC	137,134		2,109,001
2	^(g) Bonneville Power Administration - USBR	104,128		1,552,079
3	^(g) Bonneville Power Administration - PF	491,704		7,956,221
4	^(g) Milner Irrigation District	17,430		17,430
5	Seattle City Light	109,696		109,696
6	^(g) PacifiCorp	925		13,329
7	^(f) United States Bureau of Indian Affairs	64,640		64,640
8	AmpRenew Offtake I LLC	3,300		3,300
9	West Point RNG LLC	4,974		4,974
10	AmpRenew Offtake I LLC	64,406		64,406
11	Bonneville Power Administration	3,220,290		3,220,290
12	Bonneville Power Administration	3,220,290		3,220,290
13	Energy Keepers, Inc.	1,155,332		1,155,332
14	Mercuria Energy America, LLC	2,769,449		2,769,449
15	PacifiCorp Inc.	7,760,899		7,760,899
16	PacifiCorp Inc.	4,669,421		4,669,421
17	PacifiCorp Inc.	3,993,160		3,993,160
18	Powerex Corporation	6,440,580		6,440,580
19	Seattle City Light	3,039,693		3,039,693

20	West Point RNG LLC	64,406	64,406
21	Adapture Renewables, Inc. (Morgan Solar)	3,236	3,236
22	Adapture Renewables, Inc. (Ontario Solar Center)	205	205
23	Adapture Renewables, Inc. (Vale I Solar)	101	101
24	Altop Energy Trading, LLC	11,892	11,892
25	Altop Energy Trading, LLC	13,818	13,818
26	Altop Energy Trading, LLC	12,006	12,006
27	Altop Energy Trading, LLC	2,997	2,997
28	Altop Energy Trading, LLC	95	95
29	Altop Energy Trading, LLC	1,897	1,897
30	Altop Energy Trading, LLC	863	863
31	Altop Energy Trading, LLC	8,412	8,412
32	Altop Energy Trading, LLC	2,750	2,750
33	Altop Energy Trading, LLC	36,389	36,389
34	Altop Energy Trading, LLC	7,407	7,407
35	Altop Energy Trading, LLC	1,328	1,328
36	Altop Energy Trading, LLC	1,214	1,214
37	Altop Energy Trading, LLC	237	237
38	Altop Energy Trading, LLC	1,660	1,660
39	Altop Energy Trading, LLC	22,628	22,628
40	Altop Energy Trading, LLC	1,299	1,299
41	Altop Energy Trading, LLC	2,086	2,086
42	Altop Energy Trading, LLC	1,963	1,963
43	Altop Energy Trading, LLC	7,587	7,587
44	Arizona Public Service	13	13
45	Avangrid Renewables, LLC	816	816
46	Avangrid Renewables, LLC	15,959	15,959
47	Avangrid Renewables, LLC	1,632	1,632
48	Avangrid Renewables, LLC	23,334	23,334
49	Avangrid Renewables, LLC	132,129	132,129
50	Avangrid Renewables, LLC	544	544
51	Avista Corporation	3,845	3,845
52	Benson Creek Windfarm, LLC	2,162	2,162
53	Bonneville Power Administration	1,690	1,690
54	Bonneville Power Administration	621	621
55	Bonneville Power Administration	14	14
56	Bonneville Power Administration	509	509
57	Bonneville Power Administration	1,069	1,069
58	Bonneville Power Administration	7,941	7,941

59	Bonneville Power Administration	137,030	137,030
60	Bonneville Power Administration	3,468	3,468
61	Bonneville Power Administration	11,522	11,522
62	Bonneville Power Administration	217,775	217,775
63	Bonneville Power Administration	9,064	9,064
64	Bonneville Power Administration	1,144	1,144
65	Bonneville Power Administration	119	119
66	Bonneville Power Administration	20	20
67	Bonneville Power Administration	98	98
68	Bonneville Power Administration	1,127	1,127
69	Bonneville Power Administration	526	526
70	Bonneville Power Administration	85	85
71	Brookfield Renewable Trading & Marketing	270	270
72	CP Energy Marketing (US) Inc.	1,063	1,063
73	Durbin Creek Windfarm, LLC	2,162	2,162
74	Dynasty Power Inc.	31,874	31,874
75	Dynasty Power Inc.	14,612	14,612
76	Dynasty Power Inc.	28,651	28,651
77	Dynasty Power Inc.	1,164	1,164
78	Dynasty Power Inc.	18	18
79	Dynasty Power Inc.	5,802	5,802
80	Dynasty Power Inc.	1,791	1,791
81	Dynasty Power Inc.	8,237	8,237
82	Dynasty Power Inc.	5,175	5,175
83	Dynasty Power Inc.	146,477	146,477
84	Dynasty Power Inc.	90	90
85	Dynasty Power Inc.	3,510	3,510
86	Dynasty Power Inc.	10,386	10,386
87	Dynasty Power Inc.	591	591
88	Dynasty Power Inc.	51,375	51,375
89	Dynasty Power Inc.	10,762	10,762
90	Dynasty Power Inc.	5,318	5,318
91	Dynasty Power Inc.	895	895
92	Dynasty Power Inc.	65,843	65,843
93	Dynasty Power Inc.	34,560	34,560
94	Dynasty Power Inc.	985	985
95	Dynasty Power Inc.	8,524	8,524
96	Dynasty Power Inc.	3,223	3,223
97	Dynasty Power Inc.	914,642	914,642
98	Dynasty Power Inc.	54,275	54,275

99	Dynasty Power Inc.	51,661	51,661
100	Dynasty Power Inc.	4,530	4,530
101	EDF Trading North America, LLC	177	177
102	EDF Trading North America, LLC	19	19
103	EDF Trading North America, LLC	19	19
104	Energy Keepers, Inc.	216	216
105	Energy Keepers, Inc.	3,881	3,881
106	Energy Keepers, Inc.	394	394
107	Energy Keepers, Inc.	6,449	6,449
108	Energy Keepers, Inc.	1,299	1,299
109	Energy Keepers, Inc.	9,937	9,937
110	Energy Keepers, Inc.	1,692	1,692
111	Energy Keepers, Inc.	57	57
112	Energy Keepers, Inc.	140	140
113	Energy Keepers, Inc.	984	984
114	Energy Keepers, Inc.	69	69
115	Energy Keepers, Inc.	293	293
116	Energy Keepers, Inc.	598	598
117	Energy Keepers, Inc.	4,683	4,683
118	Energy Keepers, Inc.	7,172	7,172
119	Energy Keepers, Inc.	696	696
120	Energy Keepers, Inc.	21,471	21,471
121	Energy Keepers, Inc.	52,438	52,438
122	Energy Keepers, Inc.	10,109	10,109
123	Energy Keepers, Inc.	403	403
124	Energy Keepers, Inc.	3,404	3,404
125	Energy Keepers, Inc.	1,673	1,673
126	Energy Keepers, Inc.	1,299	1,299
127	Energy Keepers, Inc.	20,696	20,696
128	Energy Keepers, Inc.	3,136	3,136
129	Energy Keepers, Inc.	2,981	2,981
130	Guzman Energy Group LLC	29,368	29,368
131	Guzman Energy Group LLC	1,846	1,846
132	Guzman Energy Group LLC	2,882	2,882
133	Guzman Energy Group LLC	22,471	22,471
134	Guzman Energy Group LLC	3,562	3,562
135	Guzman Energy Group LLC	5,343	5,343
136	Guzman Energy Group LLC	56,599	56,599
137	Guzman Energy Group LLC	4,857	4,857
138	Guzman Energy Group LLC	6,897	6,897

139	Guzman Energy Group LLC	8,807	8,807
140	Guzman Energy Group LLC	1,133	1,133
141	Guzman Energy Group LLC	2,040	2,040
142	Guzman Energy Group LLC	3,562	3,562
143	Guzman Energy Group LLC	3,724	3,724
144	Guzman Energy Group LLC	3,626	3,626
145	Guzman Energy Group LLC	162	162
146	Guzman Energy Group LLC	1,813	1,813
147	Guzman Energy Group LLC	19,751	19,751
148	Guzman Energy Group LLC	7,480	7,480
149	Guzman Energy Group LLC	1,230	1,230
150	Guzman Energy Group LLC	66,086	66,086
151	Guzman Energy Group LLC	1,943	1,943
152	Guzman Energy Group LLC	1,036	1,036
153	Guzman Energy Group LLC	15,736	15,736
154	Guzman Energy Group LLC	615	615
155	Guzman Energy Group LLC	19,816	19,816
156	Guzman Energy Group LLC	9,228	9,228
157	Guzman Energy Group LLC	19,201	19,201
158	Guzman Energy Group LLC	38,920	38,920
159	Guzman Energy Group LLC	17,323	17,323
160	Guzman Energy Group LLC	20,140	20,140
161	Guzman Energy Group LLC	2,428	2,428
162	Guzman Energy Group LLC	3,400	3,400
163	Idaho Wind Partners 1, LLC (Pilgrim Stage Station Wind)	2,533	2,533
164	Jett Creek Windfarm, LLC	2,162	2,162
165	Macquarie Energy, LLC	454	454
166	Macquarie Energy, LLC	2,622	2,622
167	Macquarie Energy, LLC	45,779	45,779
168	Macquarie Energy, LLC	52	52
169	Macquarie Energy, LLC	75,302	75,302
170	Macquarie Energy, LLC	5,087	5,087
171	Macquarie Energy, LLC	13,617	13,617
172	Macquarie Energy, LLC	297	297
173	Macquarie Energy, LLC	3,933	3,933
174	Macquarie Energy, LLC	4,090	4,090
175	Macquarie Energy, LLC	787	787
176	Macquarie Energy, LLC	6,030	6,030
177	Macquarie Energy, LLC	3,636	3,636

178	Macquarie Energy, LLC	13,739	13,739
179	Macquarie Energy, LLC	2,709	2,709
180	Macquarie Energy, LLC	69,324	69,324
181	Macquarie Energy, LLC	13,984	13,984
182	Macquarie Energy, LLC	50,324	50,324
183	Macquarie Energy, LLC	15,889	15,889
184	Macquarie Energy, LLC	5,244	5,244
185	Macquarie Energy, LLC	6,992	6,992
186	Macquarie Energy, LLC	348,245	348,245
187	Macquarie Energy, LLC	181,752	181,752
188	Macquarie Energy, LLC	4,807	4,807
189	Macquarie Energy, LLC	11,746	11,746
190	Mag Energy Solutions	13,557	13,557
191	Mag Energy Solutions	30,408	30,408
192	Mag Energy Solutions	15,001	15,001
193	Mag Energy Solutions	228	228
194	Mag Energy Solutions	26,151	26,151
195	Mag Energy Solutions	36,489	36,489
196	Mag Energy Solutions	659	659
197	Mag Energy Solutions	203	203
198	Mag Energy Solutions	104,222	104,222
199	Mag Energy Solutions	9,502	9,502
200	Mag Energy Solutions	4,460	4,460
201	Mag Energy Solutions	81,087	81,087
202	Mercuria Energy America, LLC	0	0
203	Mercuria Energy America, LLC	0	0
204	Mercuria Energy America, LLC	0	0
205	Mercuria Energy America, LLC	0	0
206	Mercuria Energy America, LLC	0	0
207	Mercuria Energy America, LLC	0	0
208	Mercuria Energy America, LLC	0	0
209	Mercuria Energy America, LLC	0	0
210	Mercuria Energy America, LLC	0	0
211	Mercuria Energy America, LLC	0	0
212	Mercuria Energy America, LLC	0	0
213	Mercuria Energy America, LLC	0	0
214	Mercuria Energy America, LLC	0	0
215	MFT Energy US Power LLC	10	10
216	MFT Energy US Power LLC	21,139	21,139
217	Morgan Stanley Capital Group. Inc.	19,644	19,644

218	Morgan Stanley Capital Group. Inc.	1,864	1,864
219	Morgan Stanley Capital Group. Inc.	13,145	13,145
220	Morgan Stanley Capital Group. Inc.	12,859	12,859
221	Morgan Stanley Capital Group. Inc.	4,866	4,866
222	Morgan Stanley Capital Group. Inc.	586	586
223	Morgan Stanley Capital Group. Inc.	97,417	97,417
224	Morgan Stanley Capital Group. Inc.	6,653	6,653
225	Morgan Stanley Capital Group. Inc.	6,625	6,625
226	Morgan Stanley Capital Group. Inc.	384	384
227	Morgan Stanley Capital Group. Inc.	3,651	3,651
228	Morgan Stanley Capital Group. Inc.	78,904	78,904
229	Morgan Stanley Capital Group. Inc.	322,443	322,443
230	Morgan Stanley Capital Group. Inc.	2,478	2,478
231	Morgan Stanley Capital Group. Inc.	1,277	1,277
232	Morgan Stanley Capital Group. Inc.	162,171	162,171
233	Morgan Stanley Capital Group. Inc.	53,131	53,131
234	Morgan Stanley Capital Group. Inc.	45,599	45,599
235	Morgan Stanley Capital Group. Inc.	20,007	20,007
236	Morgan Stanley Capital Group. Inc.	2,401	2,401
237	Morgan Stanley Capital Group. Inc.	956	956
238	Morgan Stanley Capital Group. Inc.	50,667	50,667
239	Morgan Stanley Capital Group. Inc.	5,208	5,208
240	Morgan Stanley Capital Group. Inc.	22,764	22,764
241	Morgan Stanley Capital Group. Inc.	796	796
242	Morgan Stanley Capital Group. Inc.	984	984
243	Morgan Stanley Capital Group. Inc.	60,824	60,824
244	Morgan Stanley Capital Group. Inc.	1,724	1,724
245	Morgan Stanley Capital Group. Inc.	131,651	131,651
246	Morgan Stanley Capital Group. Inc.	7,435	7,435
247	Morgan Stanley Capital Group. Inc.	2,234	2,234
248	Morgan Stanley Capital Group. Inc.	19,462	19,462
249	Morgan Stanley Capital Group. Inc.	127,120	127,120
250	Morgan Stanley Capital Group. Inc.	4,202	4,202
251	Morgan Stanley Capital Group. Inc.	21,284	21,284
252	Morgan Stanley Capital Group. Inc.	2,792	2,792
253	Morgan Stanley Capital Group. Inc.	9,257	9,257
254	Morgan Stanley Capital Group. Inc.	3,763	3,763
255	Morgan Stanley Capital Group. Inc.	2,220	2,220
256	Morgan Stanley Capital Group. Inc.	586	586
257	Morgan Stanley Capital Group. Inc.	1,627	1,627

258	Morgan Stanley Capital Group. Inc.	4,663		4,663
259	Morgan Stanley Capital Group. Inc.	7,421		7,421
260	Nevada Power Company d/b/a NV Energy	9,821		9,821
261	NorthWestern Energy	18,390		18,390
262	PacifiCorp Inc.	47,623		47,623
263	PacifiCorp Inc.	14,829		14,829
264	PacifiCorp Inc.	116,011		116,011
265	PacifiCorp Inc.	43,039		43,039
266	PacifiCorp Inc.	98,380		98,380
267	PacifiCorp Inc.	505,319		505,319
268	PacifiCorp Inc.	4,976		4,976
269	PacifiCorp Inc.	76,910		76,910
270	PacifiCorp Inc.	52,364		52,364
271	PacifiCorp Inc.	16,318		16,318
272	PacifiCorp Inc.	8,972		8,972
273	PacifiCorp Inc.	10,167		10,167
274	PacifiCorp Inc.	882		882
275	PacifiCorp Inc.	1,592,417		1,592,417
276	PacifiCorp Inc.	705		705
277	Phillips 66 Energy Trading LLC	28		28
278	Phillips 66 Energy Trading LLC	3,955		3,955
279	Phillips 66 Energy Trading LLC	147,639		147,639
280	Phillips 66 Energy Trading LLC	3,231		3,231
281	Phillips 66 Energy Trading LLC	22,949		22,949
282	Phillips 66 Energy Trading LLC	102,548		102,548
283	Phillips 66 Energy Trading LLC	12,125		12,125
284	Phillips 66 Energy Trading LLC	536,720		536,720
285	Phillips 66 Energy Trading LLC	14,538		14,538
286	Phillips 66 Energy Trading LLC	3,713		3,713
287	Phillips 66 Energy Trading LLC	5,784		5,784
288	Phillips 66 Energy Trading LLC	19,199		19,199
289	Phillips 66 Energy Trading LLC	297		297
290	Phillips 66 Energy Trading LLC	33,644		33,644
291	Phillips 66 Energy Trading LLC	9,404		9,404
292	Phillips 66 Energy Trading LLC	17,639		17,639
293	Phillips 66 Energy Trading LLC	27,545		27,545
294	Phillips 66 Energy Trading LLC	1,625		1,625
295	Phillips 66 Energy Trading LLC	561,554		561,554
296	Phillips 66 Energy Trading LLC	1,857		1,857
297	Phillips 66 Energy Trading LLC	1,615		1,615

298	Phillips 66 Energy Trading LLC	1,393	1,393
299	Phillips 66 Energy Trading LLC	13,564	13,564
300	Phillips 66 Energy Trading LLC	1,188	1,188
301	Phillips 66 Energy Trading LLC	5,440	5,440
302	Phillips 66 Energy Trading LLC	181,460	181,460
303	Phillips 66 Energy Trading LLC	11,902	11,902
304	Phillips 66 Energy Trading LLC	158,436	158,436
305	Phillips 66 Energy Trading LLC	10,713	10,713
306	Phillips 66 Energy Trading LLC	2,017,502	2,017,502
307	Phillips 66 Energy Trading LLC	928	928
308	Phillips 66 Energy Trading LLC	67,047	67,047
309	Phillips 66 Energy Trading LLC	67,103	67,103
310	Phillips 66 Energy Trading LLC	28,315	28,315
311	Phillips 66 Energy Trading LLC	169,298	169,298
312	Phillips 66 Energy Trading LLC	111,507	111,507
313	Portland General Electric	2,160	2,160
314	Portland General Electric	16,462	16,462
315	Portland General Electric	4,755	4,755
316	Portland General Electric	184	184
317	Portland General Electric	6,952	6,952
318	Powerex Corp.	4	4
319	Powerex Corp.	18	18
320	Powerex Corp.	294	294
321	Powerex Corp.	5,697	5,697
322	Powerex Corp.	1,362	1,362
323	Powerex Corp.	242	242
324	Powerex Corp.	75	75
325	Powerex Corp.	625	625
326	Powerex Corp.	103	103
327	Powerex Corp.	2,357	2,357
328	Powerex Corp.	1,307	1,307
329	Powerex Corp.	2,304	2,304
330	Powerex Corp.	444	444
331	Powerex Corp.	10,197	10,197
332	Powerex Corp.	1,208	1,208
333	Powerex Corp.	10,678	10,678
334	Powerex Corp.	7,622	7,622
335	Powerex Corp.	380	380
336	Powerex Corp.	215	215
337	Powerex Corp.	202	202

338	Powerex Corp.	108	108
339	Powerex Corp.	217	217
340	Powerex Corp.	167	167
341	Powerex Corp.	250	250
342	Powerex Corp.	1,231	1,231
343	Powerex Corp.	778	778
344	Powerex Corp.	17	17
345	Powerex Corp.	2,097	2,097
346	Powerex Corp.	2,472	2,472
347	Powerex Corp.	162	162
348	Powerex Corp.	453	453
349	Powerex Corp.	3,808	3,808
350	Powerex Corp.	494	494
351	Powerex Corp.	2,909	2,909
352	Powerex Corp.	220	220
353	Powerex Corp.	1,432	1,432
354	Powerex Corp.	951	951
355	Powerex Corp.	1,545	1,545
356	Powerex Corp.	318	318
357	Powerex Corp.	1,299	1,299
358	Powerex Corp.	2,125	2,125
359	Powerex Corp.	5	5
360	Powerex Corp.	87	87
361	Powerex Corp.	3,164	3,164
362	Powerex Corp.	21	21
363	Powerex Corp.	455	455
364	Powerex Corp.	5,026	5,026
365	Powerex Corp.	686	686
366	Powerex Corp.	501	501
367	Powerex Corp.	77	77
368	Powerex Corp.	5,771	5,771
369	Powerex Corp.	4,042	4,042
370	Powerex Corp.	52,095	52,095
371	Powerex Corp.	8,713	8,713
372	Powerex Corp.	22	22
373	Powerex Corp.	42	42
374	Powerex Corp.	4,857	4,857
375	Powerex Corp.	87	87
376	Powerex Corp.	207	207
377	Powerex Corp.	18,117	18,117

378	Powerex Corp.	3,043	3,043
379	Powerex Corp.	227	227
380	Powerex Corp.	556	556
381	Powerex Corp.	1,365	1,365
382	Powerex Corp.	155	155
383	Powerex Corp.	9,108	9,108
384	Powerex Corp.	36	36
385	Powerex Corp.	480	480
386	Powerex Corp.	1,201	1,201
387	Powerex Corp.	89	89
388	Powerex Corp.	391	391
389	Powerex Corp.	561	561
390	Powerex Corp.	30	30
391	Powerex Corp.	1,357	1,357
392	Powerex Corp.	601	601
393	Powerex Corp.	797	797
394	Powerex Corp.	298	298
395	Powerex Corp.	5,415	5,415
396	Powerex Corp.	1,492	1,492
397	Powerex Corp.	1,771	1,771
398	Powerex Corp.	9,636	9,636
399	Powerex Corp.	97	97
400	Powerex Corp.	39	39
401	Powerex Corp.	79	79
402	Powerex Corp.	51	51
403	Powerex Corp.	9,826	9,826
404	Powerex Corp.	9	9
405	Powerex Corp.	601	601
406	Powerex Corp.	661	661
407	Powerex Corp.	167	167
408	Powerex Corp.	210	210
409	Powerex Corp.	528	528
410	Powerex Corp.	376	376
411	Powerex Corp.	280	280
412	Prospector Windfarm, LLC	2,162	2,162
413	Puget Sound Energy	21	21
414	Puget Sound Energy	8,877	8,877
415	Puget Sound Energy	677	677
416	Puget Sound Energy	370	370
417	Puget Sound Energy	1,799	1,799

418	Puget Sound Energy	8,592	8,592
419	Puget Sound Energy	95,419	95,419
420	Rainbow Energy Marketing Corporation	1,527	1,527
421	Rainbow Energy Marketing Corporation	10,879	10,879
422	Rainbow Energy Marketing Corporation	2,031	2,031
423	Rainbow Energy Marketing Corporation	1,160	1,160
424	Rainbow Energy Marketing Corporation	2,290	2,290
425	Rainbow Energy Marketing Corporation	519	519
426	Rainbow Energy Marketing Corporation	550	550
427	Rainbow Energy Marketing Corporation	847	847
428	Rainbow Energy Marketing Corporation	5,100	5,100
429	Rainbow Energy Marketing Corporation	5,001	5,001
430	Rainbow Energy Marketing Corporation	3,672	3,672
431	Rainbow Energy Marketing Corporation	4,581	4,581
432	Rainbow Energy Marketing Corporation	8,322	8,322
433	Rainbow Energy Marketing Corporation	37,890	37,890
434	Rainbow Energy Marketing Corporation	34,149	34,149
435	Rainbow Energy Marketing Corporation	2,168	2,168
436	Rainbow Energy Marketing Corporation	130	130
437	Rainbow Energy Marketing Corporation	2,290	2,290
438	Rainbow Energy Marketing Corporation	92	92
439	Rainbow Energy Marketing Corporation	6,108	6,108
440	Riley Solar I	5,318	5,318
441	Rockland Wind Farm, LLC	2,941	2,941
442	Seattle City Light	0	0
443	Seattle City Light	0	0
444	Seattle City Light	0	0
445	Seattle City Light	0	0
446	Seattle City Light	0	0
447	Seattle City Light	0	0
448	Seattle City Light	0	0
449	Seattle City Light	0	0
450	Shell Energy North America (US), L.P.	3,544	3,544
451	Shell Energy North America (US), L.P.	5,837	5,837
452	Shell Energy North America (US), L.P.	11,873	11,873
453	Shell Energy North America (US), L.P.	585	585
454	Shell Energy North America (US), L.P.	398	398
455	Shell Energy North America (US), L.P.	877	877
456	Shell Energy North America (US), L.P.	12,399	12,399
457	Shell Energy North America (US), L.P.	2,772	2,772

458	Shell Energy North America (US), L.P.	6,621	6,621
459	Shell Energy North America (US), L.P.	3,755	3,755
460	Shell Energy North America (US), L.P.	7,650	7,650
461	Shell Energy North America (US), L.P.	1,088	1,088
462	Shell Energy North America (US), L.P.	70	70
463	Shell Energy North America (US), L.P.	7,709	7,709
464	Shell Energy North America (US), L.P.	807	807
465	Shell Energy North America (US), L.P.	8,609	8,609
466	Shell Energy North America (US), L.P.	6,656	6,656
467	Shell Energy North America (US), L.P.	23,804	23,804
468	Shell Energy North America (US), L.P.	714	714
469	Shell Energy North America (US), L.P.	819	819
470	Shell Energy North America (US), L.P.	784	784
471	Shell Energy North America (US), L.P.	30,823	30,823
472	Shell Energy North America (US), L.P.	117	117
473	Shell Energy North America (US), L.P.	117	117
474	Shell Energy North America (US), L.P.	5,825	5,825
475	Shell Energy North America (US), L.P.	784	784
476	Shell Energy North America (US), L.P.	3,556	3,556
477	Shell Energy North America (US), L.P.	1,778	1,778
478	Starvation Solar I, LLC	7,759	7,759
479	Suntex Solar, LLC	4,829	4,829
480	TEC Energy Inc.	402	402
481	TEC Energy Inc.	4,402	4,402
482	Tenaska Power Services	1,910	1,910
483	Tenaska Power Services	34,206	34,206
484	Tenaska Power Services	163	163
485	Tenaska Power Services	336	336
486	Tenaska Power Services	391	391
487	Tenaska Power Services	119	119
488	The Energy Authority, Inc.	500	500
489	The Energy Authority, Inc.	1,412	1,412
490	The Energy Authority, Inc.	2,758	2,758
491	The Energy Authority, Inc.	13,823	13,823
492	The Energy Authority, Inc.	5,110	5,110
493	The Energy Authority, Inc.	278	278
494	The Energy Authority, Inc.	139	139
495	The Energy Authority, Inc.	139	139
496	The Energy Authority, Inc.	21,980	21,980
497	The Energy Authority, Inc.	584	584

498	The Energy Authority, Inc.	111	111
499	The Energy Authority, Inc.	21,280	21,280
500	The Energy Authority, Inc.	8,802	8,802
501	The Energy Authority, Inc.	434	434
502	The Energy Authority, Inc.	556	556
503	The Energy Authority, Inc.	556	556
504	The Energy Authority, Inc.	1,223	1,223
505	The Energy Authority, Inc.	556	556
506	The Energy Authority, Inc.	778	778
507	The Energy Authority, Inc.	2,224	2,224
508	The Energy Authority, Inc.	14,223	14,223
509	The Energy Authority, Inc.	4,654	4,654
510	The Energy Authority, Inc.	478	478
511	The Energy Authority, Inc.	4,031	4,031
512	The Energy Authority, Inc.	26,284	26,284
513	The Energy Authority, Inc.	15,330	15,330
514	The Energy Authority, Inc.	3,336	3,336
515	The Energy Authority, Inc.	218,139	218,139
516	The Energy Authority, Inc.	7,740	7,740
517	The Energy Authority, Inc.	834	834
518	The Energy Authority, Inc.	417	417
519	The Energy Authority, Inc.	450	450
520	The Energy Authority, Inc.	1,724	1,724
521	The Energy Authority, Inc.	2,052	2,052
522	The Energy Authority, Inc.	59,029	59,029
523	The Energy Authority, Inc.	1,095	1,095
524	The Energy Authority, Inc.	106	106
525	The Energy Authority, Inc.	1,562	1,562
526	The Energy Authority, Inc.	528	528
527	TransAlta Energy Marketing (US) Inc.	7,996	7,996
528	TransAlta Energy Marketing (US) Inc.	20,501	20,501
529	TransAlta Energy Marketing (US) Inc.	191,240	191,240
530	TransAlta Energy Marketing (US) Inc.	705	705
531	TransAlta Energy Marketing (US) Inc.	822	822
532	TransAlta Energy Marketing (US) Inc.	20,795	20,795
533	TransAlta Energy Marketing (US) Inc.	3,147	3,147
534	TransAlta Energy Marketing (US) Inc.	1,526	1,526
535	TransAlta Energy Marketing (US) Inc.	29,871	29,871
536	TransAlta Energy Marketing (US) Inc.	1,139	1,139
537	TransAlta Energy Marketing (US) Inc.	37,128	37,128

538	TransAlta Energy Marketing (US) Inc.	1,033		1,033
539	TransAlta Energy Marketing (US) Inc.	35,214		35,214
540	TransAlta Energy Marketing (US) Inc.	2,419		2,419
541	TransAlta Energy Marketing (US) Inc.	249,327		249,327
542	TransAlta Energy Marketing (US) Inc.	19,092		19,092
543	TransAlta Energy Marketing (US) Inc.	2,536		2,536
544	Utah Associated Municipal Power Systems	82,540		82,540
545	Vitol Inc.	64		64
546	West Hines Solar, LLC	9,428		9,428
547	West Point RNG LLC	0		0
548	West Point RNG LLC	0		0
549	Willow Springs Windfarm, LLC	2,162		2,162
35	TOTAL	51,525,302	0	62,422,041

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority
The network service agreement between Idaho Power and the Bonneville Power Administration for the Oregon Trail Electric Cooperative expires September 30, 2028.
(b) Concept: PaymentByCompanyOrPublicAuthority
The network service agreement between Idaho Power and the Bonneville Power Administration for the USBR expires December 31, 2030.
(c) Concept: PaymentByCompanyOrPublicAuthority
The network service agreement between Idaho Power and the Bonneville Power Administration for the Priority Firm Customers expires September 30, 2028.
(d) Concept: PaymentByCompanyOrPublicAuthority
The contract between Idaho Power and the Milner Irrigation District expires December 31, 2026, with automatic annual renewals until either party cancels.
(e) Concept: PaymentByCompanyOrPublicAuthority
The contract between Idaho Power and PacifiCorp - Imnaha expires on March 31, 2026.
(f) Concept: PaymentByCompanyOrPublicAuthority
The agreement between Idaho Power and the United States Department of the Interior, Bureau of Indian Affairs is subject to termination upon 90 days written notice by the Bureau.
(g) Concept: RateScheduleTariffNumber
9, Open Access Transmission Tariff, Schedule 9 Network Integration Transmission Service
(h) Concept: RateScheduleTariffNumber
Legacy, contract prior to the Open Access Transmission Tariff
(i) Concept: RateScheduleTariffNumber
5/6, Open Access Transmission Tariff, Schedule 5/6 Operating Reserves
(j) Concept: RateScheduleTariffNumber
11, Open Access Transmission Tariff, Schedule 11 Unreserved Use Penalty

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					

28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
40	TOTAL				

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

- 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.
- 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.
- 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.
- Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
- 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.
- Enter ""TOTAL"" in column (a) as the last line.
- 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)
1	Avista Corp. - WWP Div.	^(b) LFP	246,914	246,914		6,596,000
2	Avista Corp. - WWP Div.	NF	430	430		3,814
3	Avista Corp. - WWP Div.	^(b) OS		0		(9,900)
4	Bonneville Power Administration	^(c) LFP	67,952	67,952	0	1,156,487
5	Bonneville Power Administration	NF	4,089	4,089		20,407
6	Bonneville Power Administration	SFP	1,600	1,600		7,584
7	Bonneville Power Administration	^(d) OS	0	0	0	0
8	Bonneville Power Administration	^(e) OS		0		
9	Bonneville Power Administration	^(f) OS	480	480		
10	Bonneville Power Administration	^(g) OS	6,123	6,123		
11	Bonneville Power Administration	^(h) OS	1,400	1,400		
12	Bonneville Power Administration	⁽ⁱ⁾ OS	13,914	13,914		
13	Constellation Energy Generation, LLC	^(j) OS	0	0	0	(289,249)
14	Dynasty Power Inc.	^(k) OS	0	0		(2,700)
15	NorthWestern Energy	NF	3,577	3,577	0	26,763
16	NorthWestern Energy	SFP	4,709	4,709	0	34,193
17	NorthWestern Energy	^(l) OS	0	0	0	0
18	NV Energy	NF	0	0	0	250
19	NV Energy	^(m) OS	0	0	0	0
20	PacifiCorp Inc.	⁽ⁿ⁾ LFP	42,235	42,235	0	5,586,814

21	PacifiCorp Inc.	NF	11,089	11,089	0	116,490
22	PacifiCorp Inc.	SFP	2,653	2,653	0	33,530
23	PacifiCorp Inc.	^(o) OS	0	0	0	0
24	PacifiCorp Inc.	^(o) OS	0	0	0	(1,521,412)
25	PacifiCorp Inc.	^(g) AD		0		
26	PacifiCorp Inc.	^(f) AD		0		
27	PacifiCorp Inc.	^(s) AD	0	0		
28	Portland General Electric Company	^(f) SFP	0	0		32,496
29	Seattle City Light	^(u) SFP	0	0		1,320
30	Shell Energy North America (US), L.P.	^(v) OS		0		840
31	Sierra Pacific Power Company	NF	1,824	1,824	0	9,741
32	Sierra Pacific Power Company	^(w) OS	0	0	0	0
33	Snohomish County PUD	^(x) SFP		0	0	15,495
34	Tacoma Power	^(y) SFP		0		3,970
35	TransAlta Energy Marketing (U.S.) Inc.	^(z) OS		0		(4,050)
	TOTAL		408,989	408,989	0	11,818,884

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)	...	
		Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Avista Corp. - WWP Div.		6,596,000
2	Avista Corp. - WWP Div.		3,814
3	Avista Corp. - WWP Div.		(9,900)
4	Bonneville Power Administration	0	1,156,487
5	Bonneville Power Administration		20,407
6	Bonneville Power Administration		7,584
7	Bonneville Power Administration	206,227	206,227
8	Bonneville Power Administration	1,495	1,495
9	Bonneville Power Administration		0
10	Bonneville Power Administration		0
11	Bonneville Power Administration		0
12	Bonneville Power Administration		0
13	Constellation Energy Generation, LLC	0	(289,249)
14	Dynasty Power Inc.		(2,700)
15	NorthWestern Energy	0	26,763
16	NorthWestern Energy	0	34,193
17	NorthWestern Energy	1,242	1,242
18	NV Energy	0	250
19	NV Energy	9	9
20	PacifiCorp Inc.	0	5,586,814
21	PacifiCorp Inc.	0	116,490
22	PacifiCorp Inc.	0	33,530
23	PacifiCorp Inc.	63,500	63,500
24	PacifiCorp Inc.	0	(1,521,412)
25	PacifiCorp Inc.	(641)	(641)
26	PacifiCorp Inc.	(834,949)	(834,949)

27	PacifiCorp Inc.	(1,918)	(1,918)
28	Portland General Electric Company		32,496
29	Seattle City Light		1,320
30	Shell Energy North America (US), L.P.		840
31	Sierra Pacific Power Company	0	9,741
32	Sierra Pacific Power Company	231	231
33	Snohomish County PUD	0	15,495
34	Tacoma Power		3,970
35	TransAlta Energy Marketing (U.S.) Inc.		(4,050)
	TOTAL	(564,805)	11,254,079

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode

There are 2 contracts with expiration dates of 4/30/2026 and 4/30/2027

(b) Concept: StatisticalClassificationCode

Resale Transmission Purchased

(c) Concept: StatisticalClassificationCode

There are 3 contracts with expiration dates of 12/31/2026 and 12/31/20230

(d) Concept: StatisticalClassificationCode

Ancillary services

(e) Concept: StatisticalClassificationCode

Spinning/Supplemental Reserves

(f) Concept: StatisticalClassificationCode

Capacity Reassignment - SCL

(g) Concept: StatisticalClassificationCode

Capacity Reassignment - SNPD01

(h) Concept: StatisticalClassificationCode

Capacity Reassignment - TPWP

(i) Concept: StatisticalClassificationCode

Capacity Reassignment - PGEMPG

(j) Concept: StatisticalClassificationCode

Resale Transmission Purchased

(k) Concept: StatisticalClassificationCode

Resale Transmission Purchased

(l) Concept: StatisticalClassificationCode

Ancillary services

(m) Concept: StatisticalClassificationCode

Ancillary services

(n) Concept: StatisticalClassificationCode

There are 2 contracts with expiration dates of 12/31/2027 and 5/31/2029

(o) Concept: StatisticalClassificationCode

Ancillary services

(p) Concept: StatisticalClassificationCode

Resale Transmission

(q) Concept: StatisticalClassificationCode

2024 Unreserved Use Refund

(r) Concept: StatisticalClassificationCode

2024 Rate True Up - LFP_Surcharge Rate True-up

(s) Concept: StatisticalClassificationCode

2023 Rate True Up - LFP_Surcharge Rate True-up

(t) Concept: StatisticalClassificationCode
Capacity Reassignment, BPAT is the Provider
(u) Concept: StatisticalClassificationCode
Capacity Reassignment, BPAT is the Provider
(v) Concept: StatisticalClassificationCode
Resale Transmission Purchased
(w) Concept: StatisticalClassificationCode
Ancillary services
(x) Concept: StatisticalClassificationCode
Capacity Reassignment, BPAT is the Provider
(y) Concept: StatisticalClassificationCode
Capacity Reassignment, BPAT is the Provider
(z) Concept: StatisticalClassificationCode
Resale Transmission Purchased

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	667,210
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	1,832,345
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than \$5,000	
6	DIRECTOR FEES & EXPENSES:	
7	BOLANO, ODETTE	112,096
8	ELG, ANNETTE G	140,704
9	JIBSON, RONALD W	37,255
10	JOHANSEN, JUDITH A	124,633
11	JOHNSON, DENNIS L	222,022
12	JORGENSEN, NATE	116,449
13	KENNEDY, MICHAEL	85,164
14	MADISON, SCOTT WILLIAM	110,880
15	MORRIS, SUSAN	109,395
16	NAVARRO, RICHARD J	53,625
17	PETERS, MARK T	112,977
18	NASDAQ CORPORATE SOLUTIONS LLC	39,302
19	TRAVEL, LODGING, MEETINGS	75,214
20	Corp Memberships & Subscriptions:	
21	ASSOCIATED TAXPAYERS OF IDAHO	22,000
22	BANNOCK DEVELOPMENT CORP	5,000
23	BROADRIDGE FINANCIAL SOLUTIONS	117,027
24	BUSINESS PLUS INC	10,000
25	CEATI INTERNATIONAL INC	89,300
26	CENTER FOR CORPORATE INNOVATION INC	36,250
27	CHAMBER OF COMMERCE	62,199
28	E SOURCE	58,307
29	ELECTRIC POWER RESEARCH INSTITUTE	67,783
30	IDAHO ASSOCIATION OF COMMERCE & INDUSTRY	26,395
31	IDAHO MINING ASSOCIATION	7,500
32	NORTH AMERICAN ENERGY STANDARD BOARD	8,000
33	NORTHWEST GAS ASSOCIATION	10,000
34	OREGON STATE UNIVERSITY	15,000

35	PACIFIC NW UTILITIES	57,705
36	PROCUREMENT IQ	10,182
37	SOUTHERN IDAHO ECONOMIC DEVELOPMENT	5,000
38	SOUTHWEST POWER POOL, INC	5,000
39	UTILITY TECHNOLOGY COUNCIL	21,915
40	MISC OTHER EXPENSE	47,273
41	Project Related Write-Offs:	
42	RFP Bid Fees	89,352
43	BURNS & MCDONNELL ENGINEERING	73,762
44	TRINITY CONSULTANTS INC	18,803
45	Payroll Related	275,713
46	MISC OTHER EXPENSE	237
46	<u>TOTAL</u>	4,978,975

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: PublicationAndDistributionExpensesForSecuritiesToStockholders

Pub & Distr info to Stckholders

STOCK BASED COMPENSATION	1,316,131
BUSINESS WIRE INC	10,890
D F KING & COMPANY INC	25,479
DEUTSCHE BANK TRUST CO	75,000
MARKIT NORTH AMERICA INC	43,847
MOODY'S ANALYTICS INC	47,244
Q4 INC	34,621
Payroll Related	246,932
MISC OTHER EXPENSE	<u>32,200</u>
Total	1,832,345

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

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

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

Line No.	A. Summary of Depreciation and Amortization Charges	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)
	Functional Classification (a)					
1	Intangible Plant			1,750,980		1,750,980
2	Steam Production Plant	60,535,926				60,535,926
3	Nuclear Production Plant					0
4	Hydraulic Production Plant- Conventional	27,912,495		276,093		28,188,588
5	Hydraulic Production Plant- Pumped Storage					0
5.1	Solar Production Plant	5,277				5,277
5.2	Wind Production Plant					0
5.3	Other Renewable Production Plant					0
6	Other Production Plant	19,807,341		26,490		19,833,831
7	Transmission Plant	30,356,590		34,185		30,390,775
8	Distribution Plant	54,802,338		663,462		55,465,800
9	Regional Transmission and Market Operation					0
9.1	Energy Storage Plant	22,646,480		188,672		22,835,152
10	General Plant	19,242,696		8,368,111		27,610,807
11	Common Plant-Electric					0
12	TOTAL	235,309,143	0	11,307,993	0	246,617,136

B. Basis for Amortization Charges

(a)

Line No.	C. Factors Used in Estimating Depreciation Charges					
	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)
12	31020	218			2.331%	
13	31100	101,975			3.188%	
14	31210	179,796			7.796%	
15	31220	337,531			7.687%	
16	31230	2,484			1.618%	
17	31400	116,300			6.095%	
18	31500	33,647			4.266%	
19	31600	10,730			9.599%	
20	31610	450			7.473%	
21	31640	99			0.34%	
22	31650	23			3.369%	
23	31660	0			6.711%	
24	31670	425			3.954%	
25	31680	5,255			11.31%	
26	31690	14			5.018%	
27	31700	14,791				
28	STEAM TOTAL	803,738				
29	33100	320,781				
30	33210	19,461				
31	33220	298,166				
32	33230	5,472				
33	33300	413,022				
34	33400	87,006				
35	33430	843	90 years, 0 months		2.9%	R1.5
36	33500	34,334				
37	33510	194				
38	33520	42				
39	33530	805				
40	33600	19,957				
41	HYDRO TOTAL	1,200,083				
42	34100	158,445				
43	34200	11,560				
44	34300	281,013				
45	34400	76,168				
46	34500	95,351				
47	34510	212	40 years, 0 months	0%	3.18%	S0.5

48	34530	148	40 years, 0 months	0%	3.18%	S0.5
49	34600	8,814				
50	OTHER PRODUCTION TOTAL	631,711				
51	34110	3				
52	34410	79				
53	34610	13				
54	SOLAR PRODUCTION TOTAL	95				
55	35020	39,595				
56	35022	1,490				
57	35110	6,695	52 years, 0 months	(15)%	2.18%	S0
58	35130	16,878	52 years, 0 months	(15)%	2.18%	S0
59	35200	151,330				
60	35300	533,973				
61	35400	273,826				
62	35500	275,774				
63	35510	5,799				
64	35600	342,952				
65	35900	405				
66	TRANSMISSION TOTAL	1,648,717				
67	36022	873				
68	36100	72,347				
69	36200	404,646				
70	36310	1,091	60 years, 0 months	(15)%	1.9%	S0
71	36330	12,765	60 years, 0 months	(15)%	1.9%	S0
72	36400	382,337				
73	36410	25,914				
74	36500	185,902				
75	36600	63,808				
76	36700	384,858				
77	36800	885,242				
78	36900	77,772				
79	37000	23,053				
80	37010	108,770				
81	37120	4,635				
82	37320	6,652				
83	37400	0				
84	DISTRIBUTION TOTAL	2,640,665				

85	38702	48,442	20 years, 0 months	0%	5%	
86	38703	386,918	20 years, 0 months	0%	5%	
87	38705	36,720	20 years, 0 months	0%	5%	
88	38706	14,066	20 years, 0 months	0%	5%	
89	38707	15,876	20 years, 0 months	0%	5%	
90	38708	2,981	20 years, 0 months	0%	5%	
91	38710	615	20 years, 0 months	0%	5%	
92	38711	1,420	20 years, 0 months	0%	5%	
93	ENERGY STORAGE TOTAL	507,038				
94	39011	37,624				
95	39012	163,512				
96	39110	14,038				
97	39120	26,081				
98	39121	2,550				
99	39210	735				
100	39230	9,733				
101	39240	42,770				
102	39250	2,526				
103	39260	79,274				
104	39270	11,999				
105	39290	12,954				
106	39300	10,721				
107	39400	17,110				
108	39500	16,669				
109	39600	34,045				
110	39710	2,904				
111	39720	21,183				
112	39730	32,996				
113	39740	23,799				
114	39750	5,252				
115	39800	12,759				
116	GENERAL TOTAL	581,234				
117	TOTAL DEPR PLANT	8,013,281				

Line No.	C. Factors Used in Estimating Depreciation Charges	
	Account No. (a)	Average Remaining Life (g)
12	31020	
13	31100	
14	31210	
15	31220	
16	31230	
17	31400	
18	31500	
19	31600	
20	31610	
21	31640	
22	31650	
23	31660	
24	31670	
25	31680	
26	31690	
27	31700	
28	STEAM TOTAL	
29	33100	
30	33210	
31	33220	
32	33230	
33	33300	
34	33400	
35	33430	28 years, 11 months
36	33500	
37	33510	
38	33520	
39	33530	
40	33600	
41	HYDRO TOTAL	
42	34100	
43	34200	
44	34300	
45	34400	
46	34500	
47	34510	22 years, 6 months
48	34530	22 years, 6 months

49	34600	
50	OTHER PRODUCTION TOTAL	
51	34110	
52	34410	
53	34610	
54	SOLAR PRODUCTION TOTAL	
55	35020	
56	35022	
57	35110	41 years, 1 month
58	35130	41 years, 1 month
59	35200	
60	35300	
61	35400	
62	35500	
63	35510	
64	35600	
65	35900	
66	TRANSMISSION TOTAL	
67	36022	
68	36100	
69	36200	
70	36310	48 years, 7 months
71	36330	48 years, 7 months
72	36400	
73	36410	
74	36500	
75	36600	
76	36700	
77	36800	
78	36900	
79	37000	
80	37010	
81	37120	
82	37320	
83	37400	
84	DISTRIBUTION TOTAL	
85	38702	

86	38703	
87	38705	
88	38706	
89	38707	
90	38708	
91	38710	
92	38711	
93	ENERGY STORAGE TOTAL	
94	39011	
95	39012	
96	39110	
97	39120	
98	39121	
99	39210	
100	39230	
101	39240	
102	39250	
103	39260	
104	39270	
105	39290	
106	39300	
107	39400	
108	39500	
109	39600	
110	39710	
111	39720	
112	39730	
113	39740	
114	39750	
115	39800	
116	GENERAL TOTAL	
117	TOTAL DEPR PLANT	

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: BasisAmortizationCharges

Page 336 Section B. Basis for Amortization Changes

	Balance to be Amortized at 12/31/2024	Amortization 2025	Balance to be Amortized at 12/31/2025	Remaining months of Amortization
Intangible Plant				
(1) Middle Snake Relicensing	5,105,305	511,096	4,594,209	various
(2) Swan Falls Relicensing	3,355,040	189,908	3,165,132	200
(3) Shoshone Bannock ROW	869,006	287,899	581,106	24
(4) FERC Compliance Costs	31,689,564	641,822	33,447,967	various
(5) Radio Frequency – Spectrum	2,974,378	120,255	2,854,123	285
Subtotal Intangible Plant	43,993,293	1,750,980	44,642,537	
(6) Software Plant				
Hydro Production Plant		276,093	1,730,186	
Other Production Plant		26,490	233,992	
Transmission Plant		34,185	284,269	
Distribution Plant		663,462	3,785,201	
Energy Storage Plant		188,672	2,085,935	
General Plant	54,166,143	8,368,111	60,195,033	
Subtotal Software Plant	54,166,143	9,557,013	68,314,616	
Grand Total	98,159,436	11,307,993	112,957,153	

(1) Middle Snake Relicensing – Amortized over a 30 year license period. Licenses expire July 31, 2034 and February 2035.

(2) Swan Falls Relicensing – Amortized over a 30 year license period. License expires August 31, 2042.

(3) Shoshone Bannock ROW – Termination date December 31, 2027.

(4) FERC Compliance Costs - Amortized over the term of the applicable FERC Project License.

(5) Radio Frequency – Spectrum – Amortized using a 3.38% annual rate, effective January 2022.

(6) Software Plant – Amortized over a 5, 10, 15 year period, as applicable. The Amortization 2025 and the Balance to be Amortized at 12/31/2025 are reported based upon the implementation of FERC Rule No. 898.

(b) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

Column (a)

The following new sub-accounts were created in 2025 to accommodate FERC Rule No. 898:

Line	CY	Description	PY reported within:
35	33430	Communications Equipment - Hydro	33500
47	34510	Computer Hardware - Other Prod	34600
48	34530	Communicaiton Equip - Other Prod	34600
57	35110	Computer Hardware - Transmission	35300
58	35130	Communication Equipment - Transmission	35300
70	36310	Computer Hardware - Distribution	36200
71	36330	Communicaiton Equip-Distribution	36200

The following sub-accounts were moved from Other Production to Solar Production following implementation of FERC Rule No. 898:

Line Subaccount

51	34110
52	34410
53	34610

The following sub-accounts were moved from Distribution to Energy Storage following impletmentation of FERC Rule No. 898:

Line	CY	PY
85	38702	36302
86	38703	36303
87	38705	36305
88	38706	36306
89	38707	36307
90	38708	New
91	38710	New
92	38711	New

(c) Concept: DepreciablePlantBase

Column (b)

Plant balances in column (b) are year-end plant sub-account balances.

(d) Concept: UtilityPlantEstimatedAverageServiceLife

Columns (c, d, e, f, g)

Lines 35, 47, 48, 57, 58, 70, 71

Information reported for new sub-accounts following the implementation of FERC Rule No. 898 is from the Company's most recently approved Depreciation Study Filing (IPC-E-21-18) Order No. 35272 and is based upon the original sub-accounts from which they were reclassified. See footnote (b) for sub-account reclassification information.

(e) Concept: UtilityPlantAppliedDepreciationRate

Column (e)

Line: 12 to 26

The Applied Depreciation Rates presented in column (e) for Steam Production plant sub-accounts are calculated using annual depreciation expense compared to average plant balance derived from the beginning and end of year plant balances.

(f) Concept: UtilityPlantAppliedDepreciationRate

Columns (c, d, e,)

Lines 85, 86, 87, 88, 89, 90, 91, 92

The Company has been applying a 5% annual depreciation rate to depreciable Energy Storage plant as approved in Order No. 35643, until these assets are subject to the company's next Depreciation Study regulatory filing.

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

REGULATORY COMMISSION EXPENSES

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

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	
						CURRENTLY CHARGED TO	
						Department (f)	Account No. (g)
1	Statutory fees assessed by FERC	6,155,371		6,155,371		ELECTRIC	928
2	General Regulatory matters - FERC		377,607	377,607		ELECTRIC	928
3	Oregon hydro fees	460,220		460,220		ELECTRIC	928
4	Statutory fees assessed by IPUC	86,543		86,543	26,922	ELECTRIC	928
5	Statutory fees assessed by OPUC	365,089		365,089		ELECTRIC	928
6	General Regulatory matters - OPUC		369,982	369,982		ELECTRIC	928
7	General Regulatory matters - Other		36,128	36,128		ELECTRIC	928
46	TOTAL	7,067,223	783,717	7,850,940	26,922		

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)	...		AMORTIZED DURING YEAR		
		Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	Statutory fees assessed by FERC	6,155,371				
2	General Regulatory matters - FERC	377,607				
3	Oregon hydro fees	460,220				
4	Statutory fees assessed by IPUC		78,671	928	86,543	19,050
5	Statutory fees assessed by OPUC	365,089	96,000	928		96,000
6	General Regulatory matters - OPUC	369,982				
7	General Regulatory matters - Other	36,128				
46	TOTAL	7,399,308	174,671		86,543	115,050

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D and D Performed Internally:

1. Generation

a. hydroelectric

- i. Recreation fish and wildlife
- ii. Other hydroelectric

- b. Fossil-fuel steam
- c. Internal combustion or gas turbine
- d. Nuclear
- e. Solar
- f. Wind
- g. Other renewable
- h. Unconventional generation
- i. Siting and heat rejection

2. Transmission

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.

- 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

B. Electric, R, D and D Performed Externally:

- 1. Research Support to the electrical Research Council or the Electric Power Research Institute
- 2. Research Support to Edison Electric Institute
- 3. Research Support to Nuclear Power Groups
- 4. Research Support to Others (Classify)
- 5. Total Cost Incurred

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR	
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)
1	Idaho Power did not incur any research and development expenditures in 2025.					

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

- 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).
- Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D and D Performed Internally:

1. Generation

a. hydroelectric

- i. Recreation fish and wildlife
- ii. Other hydroelectric

- b. Fossil-fuel steam
- c. Internal combustion or gas turbine
- d. Nuclear
- e. Solar
- f. Wind
- g. Other renewable
- h. Unconventional generation
- i. Siting and heat rejection

2. Transmission

- 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

B. Electric, R, D and D Performed Externally:

- 1. Research Support to the electrical Research Council or the Electric Power Research Institute
- 2. Research Support to Edison Electric Institute
- 3. Research Support to Nuclear Power Groups
- 4. Research Support to Others (Classify)
- 5. Total Cost Incurred

- 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.
- 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).
- 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.
- 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."
- Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Unamortized Accumulation (g)
1	Idaho Power did not incur any research and development expenditures in 2025.	

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	26,624,258		26,624,258
4	Transmission	5,562,272		5,562,272
5	Regional Market			0
5.1	Energy Storage	0		0
6	Distribution	22,710,776		22,710,776
7	Customer Accounts	10,203,227		10,203,227
8	Customer Service and Informational	8,637,521		8,637,521
9	Sales			0
10	Administrative and General	84,957,804		84,957,804
11	TOTAL Operation (Enter Total of lines 3 thru 10)	158,695,858	0	158,695,858
12	Maintenance			
13	Production	7,970,490		7,970,490
14	Transmission	4,124,463		4,124,463
15	Regional Market			0
15.1	Energy Storage	524,129		524,129
16	Distribution	11,081,064		11,081,064
17	Administrative and General	15,659,903		15,659,903
18	TOTAL Maintenance (Total of lines 13 thru 17)	39,360,049	0	39,360,049
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	34,594,748	0	34,594,748
21	Transmission (Enter Total of lines 4 and 14)	9,686,735	0	9,686,735
22	Regional Market (Enter Total of Lines 5 and 15)	0	0	0
22.1	Energy Storage (Enter Total of Lines 5.1 and 15.1)	524,129	0	524,129
23	Distribution (Enter Total of lines 6 and 16)	33,791,840	0	33,791,840
24	Customer Accounts (Transcribe from line 7)	10,203,227	0	10,203,227
25	Customer Service and Informational (Transcribe from line 8)	8,637,521	0	8,637,521
26	Sales (Transcribe from line 9)	0	0	0

27	Administrative and General (Enter Total of lines 10 and 17)	100,617,707	0	100,617,707
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	198,055,907	0	198,055,907
29	Gas			
30	Operation			
31	Production - Manufactured Gas			0
32	Production-Nat. Gas (Including Expl. And Dev.)			0
33	Other Gas Supply			0
34	Storage, LNG Terminaling and Processing			0
35	Transmission			0
36	Distribution			0
37	Customer Accounts	0	0	0
38	Customer Service and Informational	0	0	0
39	Sales	0	0	0
40	Administrative and General			0
41	TOTAL Operation (Enter Total of lines 31 thru 40)	0	0	0
42	Maintenance			
43	Production - Manufactured Gas			0
44	Production-Natural Gas (Including Exploration and Development)			0
45	Other Gas Supply			0
46	Storage, LNG Terminaling and Processing			0
47	Transmission			0
48	Distribution			0
49	Administrative and General			0
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	0	0	0
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	0	0	0
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,	0	0	0
54	Other Gas Supply (Enter Total of lines 33 and 45)	0	0	0
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	0	0	0
56	Transmission (Lines 35 and 47)	0	0	0
57	Distribution (Lines 36 and 48)	0	0	0
58	Customer Accounts (Line 37)	0	0	0
59	Customer Service and Informational (Line 38)	0	0	0
60	Sales (Line 39)	0	0	0
61	Administrative and General (Lines 40 and 49)	0	0	0

62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	0	0	0
63	Other Utility Departments			
64	Operation and Maintenance			0
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	198,055,907	0	198,055,907
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	105,168,867		105,168,867
69	Gas Plant			0
70	Other (provide details in footnote):			0
71	TOTAL Construction (Total of lines 68 thru 70)	105,168,867	0	105,168,867
72	Plant Removal (By Utility Departments)			
73	Electric Plant			0
74	Gas Plant			0
75	Other (provide details in footnote):			0
76	TOTAL Plant Removal (Total of lines 73 thru 75)	0	0	0
77	Other Accounts (Specify, provide details in footnote):			
78	Other Clearing Accounts	5,907,001		5,907,001
79	Stores Expense	7,523,378		7,523,378
80	Other Accounts	3,723,519		3,723,519
81	Other Work in Progress	4,894,334		4,894,334
82	Preliminary Survey and Investigation	23,938		23,938
83	Indirect Loading		73,382,055	73,382,055
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	22,072,170	73,382,055	95,454,225
96	TOTAL SALARIES AND WAGES	325,296,944	73,382,055	398,678,999

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: SalariesAndWagesOtherAccounts

Amount reported is total indirect labor loadings. Loadings are allocated to departments based on direct labor charges.

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
COMMON UTILITY PLANT AND EXPENSES			
<ol style="list-style-type: none"> 1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors. 2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used. 3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation. 4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization. 			

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					

31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

PURCHASES AND SALES OF ANCILLARY SERVICES

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

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

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)
1	Scheduling, System Control and Dispatch			253,147		
2	Reactive Supply and Voltage			18,062		
3	Regulation and Frequency Response				3,317,369	KW
4	Energy Imbalance					KWH
5	Operating Reserve - Spinning			949	4,348,446	KW
6	Operating Reserve - Supplement			546	4,348,446	KW
7	Other					
8	Total (Lines 1 thru 7)			272,704		

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)	Dollars (g)
		...
		...
1	Scheduling, System Control and Dispatch	
2	Reactive Supply and Voltage	
3	Regulation and Frequency Response	324,936
4	Energy Imbalance	
5	Operating Reserve - Spinning	425,930
6	Operating Reserve - Supplement	425,930
7	Other	
8	Total (Lines 1 thru 7)	1,176,796

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)
	NAME OF SYSTEM: Idaho Power Company System Load					
1	January	4,007	30	9	2,129	265
2	February	4,165	13	11	2,109	261
3	March	3,457	4	8	1,168	219
4	Total for Quarter 1				5,406	745
5	April	3,511	17	10	1,247	245
6	May	4,726	29	18	2,376	366
7	June	5,271	30	19	3,253	420
8	Total for Quarter 2				6,876	1,031
9	July	5,290	8	19	3,339	413
10	August	5,115	12	18	3,221	381
11	September	4,641	4	18	2,814	335
12	Total for Quarter 3				9,374	1,129
13	October	3,516	28	9	1,731	227
14	November	3,707	25	12	1,973	209
15	December	3,744	1	9	1,898	248
16	Total for Quarter 4				5,602	684
17	Total				27,258	3,589

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)	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: Idaho Power Company System Load				
1	January	1,209		404	
2	February	1,209		586	
3	March	1,209		861	
4	Total for Quarter 1	3,627	0	1,851	0
5	April	1,234		785	
6	May	1,234		750	
7	June	1,234		364	
8	Total for Quarter 2	3,702	0	1,899	0
9	July	1,234		304	
10	August	1,234		279	
11	September	1,234		258	
12	Total for Quarter 3	3,702	0	841	0
13	October	1,234		324	
14	November	1,234		291	
15	December	1,234		364	
16	Total for Quarter 4	3,702	0	979	0
17	Total	14,733	0	5,570	0

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)
	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					

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)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: Enter System				
1	January				
2	February				
3	March				
4	Total for Quarter 1				
5	April				
6	May				
7	June				
8	Total for Quarter 2				
9	July				
10	August				
11	September				
12	Total for Quarter 3				
13	October				
14	November				
15	December				
16	Total for Quarter 4				
17	Total Year to Date/Year				

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2026-04-13	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	16,179,760
3	Steam	2,905,800	23	Requirements Sales for Resale (See instruction 4, page 311.)	0
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,896,549
5	Hydro-Conventional	7,020,961	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	955,009
6.2	Wind		27.1	Total Energy Stored	240,768
6.3	Other Renewable		28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	20,272,085
7	Other	3,685,047			
8	Less Energy for Pumping				
9	Net Generation (Enter Total of lines 3 through 8)	13,611,808			
10	Purchases (other than for Energy Storage)	6,783,070			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	63,715			
13	Delivered	184,199			
14	Net Exchanges (Line 12 minus line 13)	(120,484)			
15	Transmission For Other (Wheeling)				
16	Received	8,375,904			
17	Delivered	8,378,213			
18	Net Transmission for Other (Line 16 minus line 17)	(2,309)			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	20,272,085			

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2026-04-13	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: NetTransmissionEnergyForOthersElectricPowerWheeling

Page 329 Column I differs from page 401 by (2,309) MWH, reported for Wheeling variation and BPA Energy imbalance schedules on page 401. The numbers that are shown on pages 328-330 are for account 456 wheeling only, the numbers on page 401 have to be adjusted for account 447 transmission.

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

MONTHLY PEAKS AND OUTPUT

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

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: Idaho Power Company System Load					
29	January	1,754,622	256,312	2,583	21	10
30	February	1,578,768	279,159	2,698	13	12
31	March	1,676,514	444,634	2,105	19	8
32	April	1,579,048	375,178	2,101	25	13
33	May	1,657,246	219,032	3,274	31	19
34	June	1,829,864	78,455	3,625	30	20
35	July	2,010,284	47,185	3,644	8	19
36	August	1,855,889	41,394	3,548	13	18
37	September	1,551,259	130,308	3,217	2	18
38	October	1,549,745	348,079	2,087	10	15
39	November	1,543,555	345,643	2,268	25	12
40	December	1,685,290	331,170	2,296	1	13
41	Total	20,272,084	2,896,549			

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

Steam Electric Generating Plant Statistics

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

Line No.	Item (a)	Plant Name: Bennett Mountain	Plant Name: Boardman	Plant Name: Danskin	Plant Name: Jim Bridger	Plant Name: Langley Gulch
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	GAS TURBINE	STEAM	GAS TURBINE	STEAM	GAS TURBINE
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	CONVENTIONAL	SEMI-OUTDOOR BOILER	CONVENTIONAL	SEMI-OUTDOOR BOILER	CONVENTIONAL
3	Year Originally Constructed	2005	1980	2001	1974	2012
4	Year Last Unit was Installed	2005	1980	2008	1979	2012
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	172.8		270.9	775.29	318.45
6	Net Peak Demand on Plant - MW (60 minutes)	205.12		316.72	706	302.16
7	Plant Hours Connected to Load	5,880		5,219	8,760	6,514
8	Net Continuous Plant Capability (Megawatts)	205		350		320
9	When Not Limited by Condenser Water					
10	When Limited by Condenser Water					
11	Average Number of Employees	3		5		16
12	Net Generation, Exclusive of Plant Use - kWh	1,001,579,000		928,256,000	2,457,240,000	1,794,511,000
13	Cost of Plant: Land and Land Rights	0		402,745	509,671	2,287,261
14	Structures and Improvements	1,928,450		6,500,214	75,152,539	150,004,159
15	Equipment Costs	65,383,010		148,039,900	671,268,345	259,037,331
16	Asset Retirement Costs				15,661,431	
17	Total Cost (10-23)	67,311,460		154,942,860	762,591,986	411,328,751
18	Cost per KW of Installed Capacity (line 17/5) Including	389.5339		571.9559	983.6216	1,291.6588
19	Production Expenses: Oper, Supv, & Engr	32,356	17,168	28,839	252,487	482,065
20	Fuel	43,796,613		38,314,541	57,437,432	55,190,483
21	Coolants and Water (Nuclear Plants Only)	0		0	0	0
22	Steam Expenses				4,334,941	
23	Steam From Other Sources	0		0	0	0
24	Steam Transferred (Cr)	0		0	0	0
25	Electric Expenses	553,920		1,275,145	0	3,808,625
26	Misc Steam (or Nuclear) Power Expenses	68,654	971,037	160,668	6,100,463	248,064
27	Rents				202,361	
28	Allowances				0	
29	Maintenance Supervision and Engineering	227		441	12,343	144,097
30	Maintenance of Structures	25,202		95,216	0	41,302

31	Maintenance of Boiler (or reactor) Plant	47,352		84,059	6,600,478	422,539
32	Maintenance of Electric Plant	436,130		806,443	2,143,781	2,818,882
33	Maintenance of Misc Steam (or Nuclear) Plant				9,301,948	
34	Total Production Expenses	44,960,455	988,205	40,765,352	86,386,234	63,156,056
35	Expenses per Net kWh	0.0449		0.0439	0.0352	0.0352

Line No.	Item (a)	Plant Name: Valmy
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	STEAM
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	SEMI-OUTDOOR BOILER
3	Year Originally Constructed	1981
4	Year Last Unit was Installed	1985
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	144.9
6	Net Peak Demand on Plant - MW (60 minutes)	136
7	Plant Hours Connected to Load	4,832
8	Net Continuous Plant Capability (Megawatts)	
9	When Not Limited by Condenser Water	
10	When Limited by Condenser Water	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	448,560,000
13	Cost of Plant: Land and Land Rights	675,796
14	Structures and Improvements	26,822,642
15	Equipment Costs	15,485,212
16	Asset Retirement Costs	(870,906)
17	Total Cost (10-23)	42,112,744
18	Cost per KW of Installed Capacity (line 17/5) Including	290.6332
19	Production Expenses: Oper, Supv, & Engr	1,584,322
20	Fuel	30,887,540
21	Coolants and Water (Nuclear Plants Only)	
22	Steam Expenses	1,761,544
23	Steam From Other Sources	
24	Steam Transferred (Cr)	
25	Electric Expenses	824,172
26	Misc Steam (or Nuclear) Power Expenses	738,019
27	Rents	
28	Allowances	
29	Maintenance Supervision and Engineering	163,910
30	Maintenance of Structures	255,697
31	Maintenance of Boiler (or reactor) Plant	1,492,162
32	Maintenance of Electric Plant	424,436
33	Maintenance of Misc Steam (or Nuclear) Plant	260,502
34	Total Production Expenses	38,392,304
35	Expenses per Net kWh	0.0856

35	Plant Name	Bennett Mountain	Danskin	Jim Bridger	Jim Bridger	Jim Bridger
36	Fuel Kind	Gas	Gas	Coal	Gas	Oil
37	Fuel Unit	MCF	MCF	Tons	MCF	Barrels
38	Quantity (Units) of Fuel Burned	9,705,432	9,102,339	963,776	9,635,384	5,324
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,054	1,058	9,157	1,032	140,000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.513	4.209	57.296	2.819	3.205
41	Average Cost of Fuel per Unit Burned	4.513	4.209	58.701	2.819	128.053
42	Average Cost of Fuel Burned per Million BTU	4.28	3.979	3.186	2.731	21.778
43	Average Cost of Fuel Burned per kWh Net Gen	0.044	0.041	0.035		
44	Average BTU per kWh Net Generation	10,216	10,374	11,286		

35	Plant Name	Langley Gulch	Valmy	Valmy	Valmy
36	Fuel Kind	Gas	Coal	Gas	Oil
37	Fuel Unit	MCF	Tons	MCF	Barrels
38	Quantity (Units) of Fuel Burned	11,660,919	259,169	56,653	3,674
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,061	10,358	527	138,778
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.733	0	3.135	0
41	Average Cost of Fuel per Unit Burned	4.733	117.514	3.135	106.749
42	Average Cost of Fuel Burned per Million BTU	4.461	5.687	5.944	18.315
43	Average Cost of Fuel Burned per kWh Net Gen	0.031	0.069		
44	Average BTU per kWh Net Generation	6,894	12,053		

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: YearPlantOriginallyConstructed

This footnote applies to lines 3 and 4. The Boardman Plan consists of one unit constructed jointly by Portland General Electric Company, Idaho Power Company, and Pacific Northwest Generating Company, with Idaho Power owning 10%. The unit was placed in commercial operation August 3, 1980 and ceased operations in October 2020.

(b) Concept: YearPlantOriginallyConstructed

This footnote applies to lines 3 and 4. The Jim Bridger Power Plant consists of four equal units constructed jointly by Idaho Power Company and Pacific Power and Light Company, with Idaho Power owning 1/3 and PacifiCorp owning 2/3. Unit #1 was placed in commercial operation November 30, 1974, Unit #2 December 1, 1975, Unit #3 September 1, 1976, and Unit #4 November 29, 1979.

(c) Concept: YearPlantOriginallyConstructed

This footnote applies to lines 3 and 4. The Valmy Plant consists of two units constructed jointly by Sierra Pacific Power Company and Idaho Power Company, with Sierra owning 1/2 and Idaho Power owning 1/2. Unit #1 was placed in commercial operation December 11, 1981, and Unit #2 May 21, 1985. Idaho Power halted its participation in Unit #1 from December 2019 thru September 2025. Idaho Power resumed participation in Unit #1 in October 2025.

(d) Concept: InstalledCapacityOfPlant

This footnote applies to line 5 and line 12 through 43. Information reflects Idaho Power Company's share as explained in the footnote for line 3/4.

(e) Concept: InstalledCapacityOfPlant

This footnote applies to line 5 and line 12 through 43. Information reflects Idaho Power Company's share as explained in the footnote for line 3/4.

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

Hydroelectric Generating Plant Statistics

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

Line No.	Item (a)	FERC Licensed Project No. 2736 Plant Name: American Falls	FERC Licensed Project No. 1975 Plant Name: Bliss	FERC Licensed Project No. 1971 Plant Name: Brownlee	FERC Licensed Project No. 2055 Plant Name: C J Strike	FERC Licensed Project No. 2848 Plant Name: Cascade
1	Kind of Plant (Run-of-River or Storage)	Run-of-River ^(a)	Run-of-River	Storage	Run-of-River	Run-of-River ^(b)
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Outdoor	Outdoor	Outdoor	Outdoor
3	Year Originally Constructed	1978	1949	1958	1952	1983
4	Year Last Unit was Installed	1978	1950	1980	1952	1984
5	Total installed cap (Gen name plate Rating in MW)	92.34	75.04	675	82.8	12.42
6	Net Peak Demand on Plant-Megawatts (60 minutes)	69	72	714	89	11
7	Plant Hours Connect to Load	4,745	8,759	8,651	8,687	8,741
8	Net Plant Capability (in megawatts)					
9	(a) Under Most Favorable Oper Conditions	91	80	754	99	13
10	(b) Under the Most Adverse Oper Conditions	0	1	220	84	1
11	Average Number of Employees	3	5	7	4	2
12	Net Generation, Exclusive of Plant Use - kWh	207,905,000	298,138,000	2,257,548,000	364,912,000	40,949,000
13	Cost of Plant					
14	Land and Land Rights	875,318	768,993	18,547,952	5,741,857	82,142
15	Structures and Improvements	12,764,630	1,997,158	52,087,499	14,811,898	7,341,639
16	Reservoirs, Dams, and Waterways	5,226,795	17,102,788	73,494,055	13,047,967	3,145,630
17	Equipment Costs	57,538,051	20,737,821	140,096,881	15,260,984	13,596,584
18	Roads, Railroads, and Bridges	1,282,165	486,477	2,820,134	1,602,868	122,668
19	Asset Retirement Costs					
20	Total Cost (10-23)	77,686,959	41,093,237	287,046,521	50,465,574	24,288,663
21	Cost per KW of Installed Capacity (line 20 / 5)	841.3143	547.6324	425.2541	609.4876	1,955.6089
22	Production Expenses					
23	Operation Supervision and Engineering	651,558	138,919	893,225	229,853	224,677
24	Water for Power	144,830	65,938	337,107	1,197,170	99,314
25	Hydraulic Expenses	2,533,885	569,097	845,424	1,247,864	276,260
26	Electric Expenses	123,610	94,817	328,434	96,744	147,069
27	Misc Hydraulic Power Generation Expenses	767,261	1,671,265	507,709	681,812	110,543
28	Rents	58,222	33,992	19,612	31,250	5,778
29	Maintenance Supervision and Engineering	(120)	(167)	(457)	(234)	(99)
30	Maintenance of Structures	42,813	19,275	89,814	37,690	36,905

31	Maintenance of Reservoirs, Dams, and Waterways	10,390	194,801	37,554	60,294	1,171
32	Maintenance of Electric Plant	267,024	225,451	605,971	532,818	195,636
33	Maintenance of Misc Hydraulic Plant	176,300	254,726	1,176,035	340,434	179,507
34	Total Production Expenses (total 23 thru 33)	4,775,773	3,268,114	4,840,428	4,455,695	1,276,761
35	Expenses per net kWh	0.023	0.011	0.0021	0.0122	0.0312

Line No.	Item (a)	FERC Licensed Project No. 1971 Plant Name: Common Facilities	FERC Licensed Project No. 1971 Plant Name: Hells Canyon	FERC Licensed Project No. 2061 Plant Name: Lower Salmon	FERC Licensed Project No. 2726 Plant Name: Malad	FERC Licensed Project No. 2899 Plant Name: Milner
1	Kind of Plant (Run-of-River or Storage)		Storage	Run-of-River	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)		Outdoor	Outdoor	Outdoor	Conventional
3	Year Originally Constructed		1967	1949	1948	1992
4	Year Last Unit was Installed		1967	1949	1948	1992
5	Total installed cap (Gen name plate Rating in MW)		411.08	60	21.77	59.45
6	Net Peak Demand on Plant-Megawatts (60 minutes)		450	51	25	43
7	Plant Hours Connect to Load		8,757	8,758	8,343	2,936
8	Net Plant Capability (in megawatts)					
9	(a) Under Most Favorable Oper Conditions		457	80	25	48
10	(b) Under the Most Adverse Oper Conditions		137	60	21	1
11	Average Number of Employees		5	5	1	2
12	Net Generation, Exclusive of Plant Use - kWh		2,026,526,000	197,648,000	159,866,000	34,210,000
13	Cost of Plant					
14	Land and Land Rights	114,367	2,574,125	424,428	205,376	139,356
15	Structures and Improvements	100,576,019	12,381,534	3,656,020	16,595,255	10,711,507
16	Reservoirs, Dams, and Waterways	13,556,785	56,071,364	8,195,132	7,598,336	17,779,586
17	Equipment Costs	4,152,783	58,710,487	54,781,780	19,902,441	30,390,048
18	Roads, Railroads, and Bridges	142,581	1,357,863	88,693	1,601,313	501,877
19	Asset Retirement Costs					
20	Total Cost (10-23)	118,542,535	131,095,373	67,146,053	45,902,721	59,522,374
21	Cost per KW of Installed Capacity (line 20 / 5)		318.9048	1,119.1009	2,108.5311	1,001.2174
22	Production Expenses					
23	Operation Supervision and Engineering	58,077	638,073	542,138	43,031	135,415
24	Water for Power	0	201,308	140,150	20,857	386,218
25	Hydraulic Expenses	9,531,151	411,877	340,026	604,536	872,699
26	Electric Expenses	0	214,719	163,449	18,125	140,773
27	Misc Hydraulic Power Generation Expenses	79,425	259,567	393,169	90,618	454,081
28	Rents	0	11,595	19,627	10,752	22,540
29	Maintenance Supervision and Engineering	0	(354)	(139)	(103)	480

30	Maintenance of Structures	86	51,806	122,373	20,912	60,389
31	Maintenance of Reservoirs, Dams, and Waterways	0	10,603	13,571	100,397	13,878
32	Maintenance of Electric Plant	0	426,555	185,632	129,912	245,181
33	Maintenance of Misc Hydraulic Plant	199,243	987,644	253,341	173,833	170,748
34	Total Production Expenses (total 23 thru 33)	9,867,982	3,213,393	2,173,337	1,212,870	2,502,402
35	Expenses per net kWh		0.0016	0.011	0.0076	0.0731

Line No.	Item (a)	FERC Licensed Project No. 1971 Plant Name: Oxbow	FERC Licensed Project No. 2778 Plant Name: Shoshone Falls	FERC Licensed Project No. 503 Plant Name: Swan Falls	FERC Licensed Project No. 18 Plant Name: Twin Falls	FERC Licensed Project No. 2777 Plant Name: Upper Salmon
1	Kind of Plant (Run-of-River or Storage)	Storage	Run-of-River	Run-of-River	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional	Conventional	Conventional	Outdoor
3	Year Originally Constructed	1961	1907	1910	1935	1937
4	Year Last Unit was Installed	1961	1921	1994	1995	1947
5	Total installed cap (Gen name plate Rating in MW)	190	14.73	27.17	52.9	34.5
6	Net Peak Demand on Plant-Megawatts (60 minutes)	222	15	27	45	35
7	Plant Hours Connect to Load	8,753	7,418	8,753	6,081	8,694
8	Net Plant Capability (in megawatts)					
9	(a) Under Most Favorable Oper Conditions	225	16	31	52	48
10	(b) Under the Most Adverse Oper Conditions	202	11	14	50	32
11	Average Number of Employees	6	3	3	3	4
12	Net Generation, Exclusive of Plant Use - kWh	991,273,000	52,049,000	111,026,000	44,056,000	182,035,000
13	Cost of Plant					
14	Land and Land Rights	1,212,841	313,328	309,958	255,499	207,636
15	Structures and Improvements	30,738,927	10,802,497	28,432,265	12,301,070	3,906,287
16	Reservoirs, Dams, and Waterways	35,880,444	14,825,870	15,870,088	9,031,705	20,005,994
17	Equipment Costs	25,412,990	19,379,233	32,846,634	25,056,001	10,804,278
18	Roads, Railroads, and Bridges	3,674,733	468,609	2,342,572	2,638,084	29,359
19	Asset Retirement Costs					
20	Total Cost (10-23)	96,919,935	45,789,537	79,801,517	49,282,359	34,953,554
21	Cost per KW of Installed Capacity (line 20 / 5)	510.1049	3,108.5904	2,937.1188	931.6136	1,013.1465
22	Production Expenses					
23	Operation Supervision and Engineering	495,252	612,382	224,986	431,256	140,558
24	Water for Power	232,446	26,220	61,729	392,864	131,817
25	Hydraulic Expenses	488,907	144,843	1,472,113	828,727	923,617
26	Electric Expenses	325,871	53,687	162,666	118,925	164,449
27	Misc Hydraulic Power Generation Expenses	354,042	139,885	378,640	168,474	183,568
28	Rents	12,551	13,517	31,823	21,744	19,270
29	Maintenance Supervision and Engineering	5,912	(97)	(276)	(179)	(131)
30	Maintenance of Structures	51,646	60,397	360,283	53,676	83,402

31	Maintenance of Reservoirs, Dams, and Waterways	144,223	13,883	15,162	29,492	27,814
32	Maintenance of Electric Plant	144,440	170,581	282,006	432,820	215,889
33	Maintenance of Misc Hydraulic Plant	551,252	158,661	485,521	226,162	215,742
34	Total Production Expenses (total 23 thru 33)	2,806,542	1,393,959	3,474,653	2,703,961	2,105,995
35	Expenses per net kWh	0.0028	0.0268	0.0313	0.0614	0.0116

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: PlantKind American Falls generating capacity is dependent upon water releases controlled by the USBR.
(b) Concept: PlantKind Cascade generating capacity is dependent upon water releases controlled by the USBR.
(c) Concept: PlantKind Upstream storage in Brownlee Reservoir.
(d) Concept: PlantKind Lower Malad maximum demand 15,000 Kw, Upper Malad maximum demand 9,000 Kw non-coincident.
(e) Concept: PlantKind Upstream storage in Brownlee Reservoir.

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

Pumped Storage Generating Plant Statistics

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

Line No.	Item (a)	FERC Licensed Project No. 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))				

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)
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))

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)
1	Clear Lakes	1937	2.50	2.4	11,862	8,054,218	3,221,687
2	Thousand Springs	1912	6.80	7.5	51,927	14,542,395	2,138,588
3	^(a) Salmon Diesel	1967	5.00	5.5	37	1,083,020	216,604

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)	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	Clear Lakes	663,550		168,275			Hydro
2	Thousand Springs	124,269		186,128			Hydro
3	^(a) Salmon Diesel				Diesel		Internal Combustion

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: PlantName

Salmon units are classified as standby.

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

ENERGY STORAGE OPERATIONS (Large Plants)

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

Line No.	Name of the Energy Storage Project (a)	Location of the Project (b)	MWHs (c)	MWHs delivered to the grid (d)	MWHs Lost During Conversion, Storage and Discharge of Energy (e)	MWHs Sold (f)	Revenues from Energy Storage Operations (g)	Power Purchased for Storage Operations (555.1) (Dollars) (h)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (i)	Other Costs Associated with Self-Generated Power (Dollars) (j)	Account for Project Costs (k)
1	Hemingway 1 BESS	Owyhee County, ID	65,921	58,239	7,682						101387
2											
3	Hemingway 2 BESS	Owyhee County, ID	23,667	21,009	2,658						101387
4											
5	Black Mesa BESS	Elmore County, ID	40,571	37,745	2,826						101387
6											
7	Franklin BESS	Twin Falls County, ID	77,653	68,718	8,935						101387
8											
9	Happy Valley BESS	Canyon County, ID	62,904	55,057	7,847						101387
10											
35	TOTAL		270,716	240,768	29,948						

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)	Total Project Plant Costs (l)
1	Hemingway 1 BESS	117,205,909
2		
3	Hemingway 2 BESS	66,353,232
4		
5	Black Mesa BESS	56,789,676
6		
7	Franklin BESS	121,405,375
8		
9	Happy Valley BESS	119,462,012
10		
35	TOTAL	481,216,204

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

ENERGY STORAGE OPERATIONS (Small Plants)

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

Line No.	Name of the Energy Storage Project (a)	Location of the Project (b)	Project Cost (c)	Plant Operating Expenses		
				Operations (Excluding Fuel used in Storage Operations) (d)	Maintenance (e)	Cost of fuel used in storage operations (f)
1	Elmore BESS	Elmore County, ID	8329428			
2						
3	Filer BESS	Twin Falls County, ID	4710279			
4						
5	Melba BESS	Canyon County, ID	6750423			
6						
7						
8	Weiser BESS	Washington County, ID	8620461			
9	Boise M&E BESS	Ada County, ID	101193			
10						
36	TOTAL		28,511,784			

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)	...	
		Account No. 555.1, Power Purchased for Storage Operations (g)	Other Expenses (h)
1	Elmore BESS		
2			
3	Filer BESS		
4			
5	Melba BESS		
6			
7			
8	Weiser BESS		
9	Boise M&E BESS		
10			
36	TOTAL		

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in 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)			LENGTH (Pole miles) - (In the case of underground lines report circuit miles)	On Structure of Line Designated
	From (a)	To (b)	Operating (c)	Designated (d)	Type of Supporting Structure (e)	
1	Borah	^(a) Midpoint	345	500	S Tower	62.32
2	Summer lake	^(b) Hemingway	500	500	S Tower	0.08
3	Hemingway	^(c) Midpoint	500	500	S Tower	0.15
4	Summer Lake	^(d) Hemingway	500	500	S Tower	53.07
5	Hemingway	^(e) Midpoint	500	500	S Tower	47.76
6	Jim Bridger	^(f) Goshen	345	345	S Tower	66.15
7	State Line	Midpoint	345	345	S Tower	76.04
8	Rogerson	Midpoint	345	345	S Tower	1.08
9	Kinport	^(g) Borah	345	345	S Tower	19.81
10	Jim Bridger	^(h) Populus	345	345	S Tower	60.93
11	Populus	⁽ⁱ⁾ Kinport	345	345	S Tower	7.42
12	Jim Bridger	^(j) Populus	345	345	S Tower	61.1
13	Populus	^(k) Borah	345	345	S Tower	9.05

14	Goshen	Kinport	345	345	S Tower	7.49
15	Midpoint	Borah #1	345	345	H Wood	51.07
16	Midpoint	Borah #2	345	345	H Wood	49.98
17	Adelaide Tap	Adelaide	345	345	H Wood	1.72
18	Quartz	LaGrande	230	230	H Wood	45.97
19	Midpoint	Hunt	230	230	S Tower	0.7
20	Brady	Antelope	230	230	H Wood	56.38
21	Brady	Treasureton	230	230	H Wood	0.08
22	Brady #1 & #2	Kinport	230	230	S Tower	17.94
23	Brownlee	Ontario	230	230	S Tower	72.67
24	Mora	Bowmont	138	230	S P Wood	4.12
25	Mora	Bowmont	138	230	H Wood	8.71
26	Caldwell	Locust	230	230	SP Steel	18.5
27	Boise Bench	Caldwell	230	230	S Tower	10.25
28	Boise Bench	Caldwell	230	230	H Wood	33.49
29	Boise Bench	Cloverdale	230	230	S Tower	16.08
30	Brownlee	Oxbow	230	230	SP Steel	10.96
31	Caldwell	Ontario	230	230	H Wood	30.06
32	Caldwell	Ontario	230	230	S Tower	3.14
33	Bennett Mtn PP	Rattlesnake TS	230	230	SP Steel	4.39
34	Borah	Hunt	230	230	H Steel	68.12
35	Danskin	Hubbard	230	230	H Steel	36.25
36	Danskin	Hubbard	230	230	SP Steel	3.57
37	Danskin	Hubbard	230	230	SP Steel	1.3
38	Danskin	Bennett Mtn	230	230	SP Steel	5.39
39	Hemingway	Bowmont	230	230	SP Steel	12.94
40	Langley Gulch	Galloway Rd	138	230	SP Steel	14.19
41	Galloway Rd	Willis Tap	138	230	SP Steel	2.09
42	Walla Walla	Hurricane	230	230	H Wood	31.66
43	Cloverdale	Hubbard	230	230	SP Steel	6.86
44	Bowmont	Hubbard	0	230		0
45	Boise Bench	Midpoint #1	230	230	S Tower	0.79
46	Boise Bench	Midpoint #1	230	230	H Wood	109.65
47	Brownlee	Quartz Jct	230	230	S Tower	1.51
48	Brownlee	Quartz Jct	230	230	H Wood	41.3
49	Brownlee	Boise Bench #1 & #2	230	230	S Tower	99.78
50	Oxbow	Brownlee	230	230	S Tower	10.32
51	Boise Bench	Midpoint #2	230	230	S Tower	3.49

52	Boise Bench	Midpoint #2	230	230	H Wood	102.13
53	Oxbow	Palette Jct	230	230	S Tower	19.98
54	Palette Jct	Imnaha	230	230	H Wood	24.43
55	Hells Canyon	Palette Jct	230	230	S Tower	9.05
56	Brownlee	Boise Bench	230	230	S Tower	102.09
57	Boise Bench	Midpoint #3	230	230	H Wood	106.29
58	Palette Jct	Enterprise	230	230	H Wood	29.6
59	Borah	Brady #2	230	230	S Tower	0.42
60	Borah	Brady #2	230	230	H Wood	3.52
61	Borah	Brady #1	230	230	H Wood	3.84
62	Goshen	G State Line	161	161	H Wood	40.89
63	Don	Goshen	161	161	S Tower	2.37
64	Don	Goshen	161	161	H Wood	16.49
65	Don	Goshen	138	161	H Wood	29.66
66	Antelope	G Goshen	161	161	H Wood	5.68
67	Goshen	S State Line	161	161	H Wood	10.9
68	Goshen	U State Line	161	161	H Wood	7.84
69	American Falls PP	Adelaide	138	138	H Wood	14.09
70	American Falls PP	Adelaide	138	138	S P Wood	0.12
71	Minidoka Loop	Adelaide	138	138	S Tower	1.13
72	Nampa	Caldwell	138	138	S P Wood	9.33
73	Skyway Tap		138	138	S P Steel	0.89
74	Upper Salmon	Mountain Home Jct	138	138	H Wood	54.36
75	Upper Salmon	Cliff	138	138	H Wood	30.81
76	Eastgate	Russet	138	138	S P Wood	2.06
77	Brady	Fremont	138	138	S Tower	1.01
78	Brady	Fremont	138	138	H Wood	24.36
79	Brady	Fremont	138	138	S P Wood	24.4
80	King	Lower Malad	138	138	H Wood	84.71
81	Orchard Tap		138	138	S P Steel	3.11
82	Emmett Jct	Payette	138	138	H Wood	66.36
83	Gulch Tap		138	138	S P Steel	2.5
84	Mountain Home AFB Tap		138	138	H Wood	6.2
85	Ontario	Quartz	138	138	H Wood	73.25
86	King	American Falls PP	138	138	S Tower	0.91
87	King	American Falls PP	138	138	H Wood	142.15
88	King	American Falls PP	138	138	S P Wood	3.71
89	King	American Falls PP	138	138	S P Steel	0.5
90	Duffin	Clawson	138	138	H Wood	6.19

91	American Falls	Brady Tie	138	138	H Wood	0.33
92	Upper Salmon A-B	King	138	138	H Wood	5.76
93	Upper Salmon B	Wells	138	138	H Wood	125.47
94	King	Wood River	138	138	H Wood	73.62
95	Toponis	Pocket	138	138	S P Wood	9.79
96	Boise Bench	Grove	138	138	S P Wood	10.49
97	Quartz	John Day	138	138	H Wood	67.37
98	Sinker Creek Tap		138	138	H Wood	2.83
99	Mora	Cloverdale	138	138	H Wood	2.51
100	Mora	Cloverdale	138	138	S P Wood	22.25
101	Mora	Cloverdale	138	138	S P Steel	0.96
102	Stoddard Jct	Stoddard Sub	138	138	S P Steel	3.8
103	Fossil Gulch Tap		138	138	H Wood	1.81
104	Wood River	Midpoint	138	138	H Wood	53.08
105	Wood River	Midpoint	138	138	S P Wood	16.32
106	Oxbow	McCall	138	138	H Wood	37.04
107	Oxbow	McCall	138	138	S P Wood	2.32
108	Lowell Jct	Nampa	138	138	S P Wood	7.53
109	Hunt	Milner	138	138	S P Wood	19.41
110	Strike	Bruneau Bridge	138	138	H Wood	13.49
111	American Falls	Kramer Sub	138	138	S P Wood	18.46
112	Pingree	Haven	138	138	S P Wood	11.72
113	Midpoint	Twin Falls	138	138	S P Wood	25.19
114	Shoshone Tap		138	138	H Wood	7.08
115	Twin Falls	Russett	138	138	S P Wood	1.71
116	Blackfoot	Aiken	46	138	S P Wood	6.27
117	Peterson	Tendoy	69	138	H Wood	56.83
118	Eastgate Tap	Eastgate	138	138	S P Wood	6.39
119	Kimberly Tap	Kimberly	138	138	S P Steel	1.84
120	Boise Bench	Mora	138	138	H Wood	13.11
121	Bowmont-Caldwell	Simplot Sub	138	138	S P Wood	0.51
122	Gary Lane	Eagle	138	138	S P Wood	6.64
123	Locust Grove	Blackcat Sub	138	138	S P Steel	9.24
124	Boise Bench	Butler	138	138	S P Wood	0.14
125	Eagle	Star	138	138	S P Wood	6.77
126	Star	Lansing	138	138	S P Steel	5.5
127	Beacon Light Tap	Beacon Light	138	138	S P Steel	4.32
128	Karcher Sub	Zilog Tap	138	138	S P Steel	3.12
129	Zilog	Can Ada	138	138	S P Steel	1.97
130	Blackcat	Can Ada	138	138	H Wood	3.42

131	Cloverdale	Wye	138	138	S P Steel	0.42
132	Victory Jct	Victory	138	138	S P Steel	1.87
133	Butler	Wye	138	138	S P Steel	2.94
134	Horseflat	Starkey	138	138	H Wood	33.97
135	Starkey	Mccall	138	138	S P Steel	2.23
136	Starkey	Mccall	138	138	H Wood	3.8
137	Starkey	Mccall	138	138	S P Steel	1.5
138	Starkey	Mccall	138	138	S P Wood	17.61
139	Chestnut	Happy Valley	138	138	S P Steel	2.75
140	Garnet	Ward	0	138		0
141	McCall	Lake Fork	138	138	S P Wood	8.89
142	McCall	Lake Fork	138	138	S Steel	2.9
143	Boulder Tap		138	138	S P Steel	1.98
144	Caldwell	Willis	138	138	S P Steel	1.3
145	Caldwell	Willis	138	138	S P Steel	3.63
146	Caldwell	Willis	138	138	S P Wood	0.87
147	Willis	Lansing	138	138	Verious	3.23
148	Valivue Tap		138	138	S P Steel	0.79
149	Raft River Tap		138	138	S P Wood	0.01
150	Bowmont	Happy Valley	138	138	S P Steel	8.65
151	Antelope	^(u) Scoville	138	138	H Wood	0.12
152	American Falls	^(u) Wheelon	138	138	H Wood	1.05
153	Bowmont	Kuna Tap	138	138	S P Steel	0.07
154	Kinport	Don #1	138	138	S Tower	1.27
155	Donn	HOKU	138	138	S P Steel	2.69
156	HOKU	Alamed	138	138	S P Steel	0.22
157	HOKU	Alamed	138	138	S P Steel	0.23
158	HOKU	Alamed	138	138	S P Steel	2.85
159	Eldridge tap		138	138	S P Steel	0.85
160	Mora	Columbia	138	138	S P Steel	0
161	Rockland Jct	Rockland Wind Farm	138	138	S P Steel	5.18
162	King	Justice	138	138	S P Wood	0.07
163	NorthView Tap		138	138	S P Wood	6.17
164	Caldwell	Ontario	138	138	H Wood	0
165	Wood River	Ketchum	0	138		0
166	Twin Falls PP Tap		138	138	H Wood	0.99
167	American Falls PP	Amercian Falls Trans ST	138	138	S P Steel	0.37
168	Lower Salmon	King Tie	138	138	H Wood	0.05
169	C J Strike	Strike Jct	138	138	S Tower	4.3

170	Strike Jct	Mountain Home Jct	138	138	H Wood	23.32
171	Elmore	Sawmill	138	138	S P Steel	3
172	Strike Jct	Bowmont	0	138	H Wood	0.05
173	Strike Jct	Bowmont	138	138	S Tower	0.36
174	Strike Jct	Bowmont	138	138	H Wood	67.89
175	Lucky Peak	Lucky Peak Jct	138	138	H Wood	4.48
176	Bliss	King	138	138	H Wood	10.51
177	Milner Deadend	Milner PP	138	138	S P Wood	1.3
178	Swan Falls Tap		138	138	H Wood	0.95
179	Hines	BPA (Harney)	115	115	H Wood	3.35
180	69 Kv Lines		69	69	H Wood	200.79
181	69 Kv Lines		69	69	S P Wood	804.18
182	46 Kv Lines		46	46	S P Wood	368.9
183	N/A					
36	TOTAL					4,706.51

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	...	Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)	
	From (a)	On Structures of Another Line (g)			Land (j)	Construction Costs (k)
1	Borah	0	1	1272 ACSR	256,380	16,113,710
2	Summer lake	0	1	1272 ACSR	0	0
3	Hemingway	0	1	1272 ACSR	0	0
4	Summer Lake	0	1	3x1272 ACSR	0	18,859,844
5	Hemingway	0	1	3x1272 ACSR	0	17,142,784
6	Jim Bridger	0	1	1272 ACSR	566,396	5,493,543
7	State Line	0	2	795 ACSR	572,296	13,063,660
8	Rogerson	0	1	795 ACSR	0	0
9	Kinport	0	1	1272 ACSR	344,220	4,419,764
10	Jim Bridger	0	1	1272 ACSR	0	9,607,821
11	Populus	0	1	1272 ACSR	0	0
12	Jim Bridger	0	1	1272 ACSR	0	9,263,039
13	Populus	0	1	1272 ACSR	0	0
14	Goshen	0	1	2x1272 ACSR	0	585,982
15	Midpoint	0	1	715.5 ACSR	283,143	20,133,011
16	Midpoint	0	2	715.5 ACSR	64,851	15,050,288
17	Adelaide Tap	0	2	715.5 ACSR	51,448	227,554
18	Quartz	0	1	795 ACSR	62,218	7,529,030
19	Midpoint	0	2	715.5 ACSR	9,145	1,014,113
20	Brady	0	1	1272 ACSR	163,320	5,459,739
21	Brady	0	1	795 ACSR	0	6,186

22	Brady #1 & #2	0	2	715.5 ACSR	18,829	1,322,651
23	Brownlee	0	1	2X954 ACSR	1,676,838	20,734,163
24	Mora	0	1	715.5 ACSR	413,793	2,585,129
25	Mora	0	1	715.5 ACSR	0	0
26	Caldwell	0	1	1590 ACSR	2,378,436	8,775,086
27	Boise Bench	0	1	1272 ACSR	2,333,671	16,305,944
28	Boise Bench	0	1	715.5 ACSR	0	0
29	Boise Bench	0	2	1272 ACSR	3,062,812	7,817,954
30	Brownlee	0	2	954 ACSR	34,174	16,026,470
31	Caldwell	0	1	2X954 ACSR	236,152	9,515,288
32	Caldwell	0	1	1272 ACSR	0	0
33	Bennett Mtn PP	0	1	1272 ACSR	81,701	1,666,354
34	Borah	0	1	1590 ACSR	624,917	22,472,247
35	Danskin	0	1	1590 ACSR	20	15,758,609
36	Danskin	0	1	1590 ACSR	0	0
37	Danskin	0	2	1590 ACSR	0	0
38	Danskin	0	1	1590 ACSR	0	3,528,033
39	Hemingway	0	1	1590 ACSR	1,854,996	9,277,980
40	Langley Gulch	0	1	1590 ACSR	948,166	9,066,739
41	Galloway Rd	0	1	1272 ACSR	0	0
42	Walla Walla	0	1	1272 ACSR	0	6,910,550
43	Cloverdale	0	2	1272 ACSR	287,582	8,909,499
44	Bowmont	0	0		1,016,569	0
45	Boise Bench	0	1	715.5 ACSR	385,287	47,114,159
46	Boise Bench	0	1	715.5 ACSR	0	0
47	Brownlee	0	1	795 ACSR	53,068	5,396,497
48	Brownlee	0	1	795 ACSR	0	0
49	Brownlee	0	2	VARIOUS	289,923	10,045,519
50	Oxbow	0	2	1272 ACSR	14,810	1,570,855
51	Boise Bench	0	1	715.5 ACSR	227,814	27,226,192
52	Boise Bench	0	1	VARIOUS	0	0
53	Oxbow	0	2	1272 ACSR	87,468	4,058,883
54	Palette Jct	0	2	1272 ACSR	171,081	4,427,654
55	Hells Canyon	0	2	1272 ACSR	44,687	1,567,365
56	Brownlee	0	2	954 ACSR	184,806	6,765,760
57	Boise Bench	0	1	715.5 ACSR	247,846	8,857,129
58	Palette Jct	0	1	1272 ACSR	84,014	2,446,347
59	Borah	0	1	1272 ACSR	3,068	878,912
60	Borah	0	1	715.5 ACSR	0	0
61	Borah	0	1	1272 ACSR	7,248	520,453

62	Goshen	0	1	250 COPPER	375,576	3,630,662
63	Don	0	2	715.5 ACSR	88,204	3,525,855
64	Don	0	2	397.5 ACSR	0	0
65	Don	0	2	397.5 ACSR	0	0
66	Antelope	0	1	397.5 ACSR	0	877,164
67	Goshen	0	1	250 COPPER	116,872	1,251,620
68	Goshen	0	1	250 COPPER	76,969	698,805
69	American Falls PP	0	2	250 COPPER	26,507	420,519
70	American Falls PP	0	2	250 COPPER	0	0
71	Minidoka Loop	0	2	715.5 ACSR	21,327	315,867
72	Nampa	0	2	795 AAC	1,798,312	8,646,562
73	Skyway Tap	0	2	1272 ACSR	0	0
74	Upper Salmon	0	1	795 ACSR	78,078	5,523,881
75	Upper Salmon	0	1	795 ACSR	43,568	3,729,855
76	Eastgate	0	1	795 AAC	270,823	566,129
77	Brady	0	2	VARIOUS	564,932	8,148,672
78	Brady	0	2	VARIOUS	0	0
79	Brady	0	2	VARIOUS	0	0
80	King	0	2	VARIOUS	276,966	14,359,427
81	Orchard Tap	0	1	795 ACSR	0	0
82	Emmett Jct	0	2	VARIOUS	60,104	26,990,231
83	Gulch Tap	0	1	715.5 ACSR	0	0
84	Mountain Home AFB Tap	0	1	397.5 ACSR	5,086	270,195
85	Ontario	0	1	VARIOUS	127,899	40,821,538
86	King	0	2	715.5 ACSR	216,920	19,041,514
87	King	0	1	715.5 ACSR	0	0
88	King	0	1	715.5 ACSR	0	0
89	King	0	1	715.5 ACSR	0	0
90	Duffin	0	1	4\0	4,191	657,511
91	American Falls	0	1	954 ACSR	0	154,612
92	Upper Salmon A-B	0	1	250 COPPER	2,741	1,086,773
93	Upper Salmon B	0	1	VARIOUS	28,491	6,915,638
94	King	0	1	VARIOUS	186,198	26,511,131
95	Toponis	0	1	397.5 ACSR	0	0
96	Boise Bench	0	2	VARIOUS	225,602	2,225,092
97	Quartz	0	1	397.5 ACSR	96,582	3,810,762
98	Sinker Creek Tap	0	1	VARIOUS	11,083	307,693
99	Mora	0	1	715.5 ACSR	3,123,380	10,416,131
100	Mora	0	1	VARIOUS	0	0
101	Mora	0	2	795AAC	0	0

102	Stoddard Jct	0	1	1272 ACSR	0	0
103	Fossil Gulch Tap	0	1	250 COPPER	450	273,345
104	Wood River	0	2	397.5 ACSR	514,480	8,620,142
105	Wood River	0	2	397.5 ACSR	0	0
106	Oxbow	0	1	397.5 ACSR	141,534	7,404,541
107	Oxbow	0	1	397.5 ACSR	0	0
108	Lowell Jct	0	2	715.5 ACSR	211,131	1,710,983
109	Hunt	0	1	715.5 ACSR	3,324	2,233,119
110	Strike	0	1	397.5 ACSR	14,927	1,058,848
111	American Falls	0	2	715.5 ACSR	13,734	2,381,462
112	Pingree	0	1	397.5 ACSR	18,223	1,362,295
113	Midpoint	0	2	VARIOUS	107,132	8,194,281
114	Shoshone Tap	0	2	397.5 ACSR	0	0
115	Twin Falls	0	1	715.5 ACSR	16,790	217,557
116	Blackfoot	0	2	715.5 ACSR	13,616	580,168
117	Peterson	0	1	397.5 ACSR	395,696	3,664,199
118	Eastgate Tap	0	1	715.5 ACSR	343,955	2,195,624
119	Kimberly Tap	0	2	795 ACSR	0	0
120	Boise Bench	0	2	715.5 ACSR	14,697	756,210
121	Bowmont-Caldwell	0	1	795 AAC	0	52,366
122	Gary Lane	0	1	795 AAC	308,141	2,254,517
123	Locust Grove	2.98	1	1272 ACSR	935,810	4,108,914
124	Boise Bench	4.02	1	1272 ACSR	34,687	1,053,149
125	Eagle	0	1	715.5 ACSR	630,977	10,084,693
126	Star	0	1	795 AAC	0	0
127	Beacon Light Tap	0	1	795 AAC	0	0
128	Karcher Sub	0	1	795 AAC	541,877	3,552,803
129	Zilog	0	1	795 AAC	0	0
130	Blackcat	0	1	397.5 ACSR	0	0
131	Cloverdale	4.02	1	1272 ACSR	140,412	2,602,599
132	Victory Jct	0	1	1272 ACSR	0	0
133	Butler	0	1	795 ACSR	134,471	1,405,436
134	Horseflat	0	1	715.5 ACSR	2,473,833	19,188,923
135	Starkey	0	2	715.5 ACSR	0	0
136	Starkey	0	1	715.5 ACSR	0	0
137	Starkey	0	1	715.5 ACSR	0	0
138	Starkey	0	1	715.5 ACSR	0	0
139	Chestnut	0	1	1272 ACSR	78,580	2,221,529
140	Garnet	0	0		40,580	0
141	McCall	0	1	715.5 ACSR	331,539	4,883,142

142	McCall	0	1	715.5 ACSR	0	0
143	Boulder Tap	0	1	715.5 ACSR	0	0
144	Caldwell	0	1	1272 ACSR	846,523	5,865,688
145	Caldwell	0	1	795 ACSR	0	0
146	Caldwell	0	1	795 ACSR	0	0
147	Willis	0	2	795 ACSR	0	0
148	Valivue Tap	0	2	795 ACSR	0	351,497
149	Raft River Tap	0	1		0	176
150	Bowmont	0	1	1272 ACSR	691,728	6,045,287
151	Antelope	0	1	397.5 ACSR	0	162,014
152	American Falls	0	1	250 COPPER	0	105,684
153	Bowmont	6.43	2	1590 ACSR	0	1,416,910
154	Kinport	0	2	715.5 ACSR	1,174	267,313
155	Donn	0	1	1272 ACSR	327,334	2,142,761
156	HOKU	0	2	1272 ACSR	0	0
157	HOKU	0	2	795 ACSR	0	0
158	HOKU	0	1	795 ACSR	0	0
159	Eldridge tap	0	1	795 ACSR	0	0
160	Mora	3.92	2	795 ACSR	0	533,011
161	Rockland Jct	0	1	795 ACSR	0	(16,973)
162	King	0	1	1590 ACSR	0	60,659
163	NorthView Tap	0	1	715.5 ACSR	105,933	4,127,058
164	Caldwell	3.1	2	795 ACSR	0	719,019
165	Wood River	0			455,241	0
166	Twin Falls PP Tap	0	1	250 COPPER	58	112,396
167	American Falls PP	0	1	715.5 ACSR	0	176,784
168	Lower Salmon	0	1	397.5 ACSR	0	74,560
169	C J Strike	0	2	715.5 ACSR	1,074	705,680
170	Strike Jct	0	1	397.5 ACSR	6,332	3,952,124
171	Elmore	0	2	1272 ACSR	0	0
172	Strike Jct	0	1	715.5 ACSR	86,651	6,168,955
173	Strike Jct	0	1	715.5 ACSR	0	0
174	Strike Jct	0	1	715.5 ACSR	0	0
175	Lucky Peak	0	2	715.5 ACSR	7	331,433
176	Bliss	0	1	715.5 ACSR	5,620	1,803,345
177	Milner Deadend	0	1	715.5 ACSR	14,968	186,543
178	Swan Falls Tap	0	1	397.5 ACSR	17,207	262,545
179	Hines	0	1	397.5 ACSR	1,978	117,103
180	69 Kv Lines	0	1	VARIOUS	3,284,990	123,634,569
181	69 Kv Lines	0	1	VARIOUS	0	0

182	46 Kv Lines	0	1	VARIOUS	1,180,291	30,966,447
183	N/A					
36	TOTAL	24.47	231		41,457,309	898,755,761

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	...	EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	From	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(l)	(m)	(n)	(o)	(p)
1	Borah	16,370,090				
2	Summer lake	0				
3	Hemingway	0				
4	Summer Lake	18,859,844				
5	Hemingway	17,142,784				
6	Jim Bridger	6,059,939				
7	State Line	13,635,956				
8	Rogerson	0				
9	Kinport	4,763,984				
10	Jim Bridger	9,607,821				
11	Populus	0				
12	Jim Bridger	9,263,039				
13	Populus	0				
14	Goshen	585,982				
15	Midpoint	20,416,154				
16	Midpoint	15,115,139				
17	Adelaide Tap	279,002				
18	Quartz	7,591,248				
19	Midpoint	1,023,258				
20	Brady	5,623,059				
21	Brady	6,186				
22	Brady #1 & #2	1,341,480				

23	Brownlee	22,411,001			
24	Mora	2,998,922			
25	Mora	0			
26	Caldwell	11,153,522			
27	Boise Bench	18,639,615			
28	Boise Bench	0			
29	Boise Bench	10,880,766			
30	Brownlee	16,060,644			
31	Caldwell	9,751,440			
32	Caldwell	0			
33	Bennett Mtn PP	1,748,055			
34	Borah	23,097,164			
35	Danskin	15,758,629			
36	Danskin	0			
37	Danskin	0			
38	Danskin	3,528,033			
39	Hemingway	11,132,976			
40	Langley Gulch	10,014,905			
41	Galloway Rd	0			
42	Walla Walla	6,910,550			
43	Cloverdale	9,197,081			
44	Bowmont	1,016,569			
45	Boise Bench	47,499,446			
46	Boise Bench	0			
47	Brownlee	5,449,565			
48	Brownlee	0			
49	Brownlee	10,335,442			
50	Oxbow	1,585,665			
51	Boise Bench	27,454,006			
52	Boise Bench	0			
53	Oxbow	4,146,351			
54	Palette Jct	4,598,735			
55	Hells Canyon	1,612,052			
56	Brownlee	6,950,566			
57	Boise Bench	9,104,975			
58	Palette Jct	2,530,361			
59	Borah	881,980			
60	Borah	0			
61	Borah	527,701			
62	Goshen	4,006,238			

63	Don	3,614,059			
64	Don	0			
65	Don	0			
66	Antelope	877,164			
67	Goshen	1,368,492			
68	Goshen	775,774			
69	American Falls PP	447,026			
70	American Falls PP	0			
71	Minidoka Loop	337,194			
72	Nampa	10,444,874			
73	Skyway Tap	0			
74	Upper Salmon	5,601,959			
75	Upper Salmon	3,773,423			
76	Eastgate	836,952			
77	Brady	8,713,604			
78	Brady	0			
79	Brady	0			
80	King	14,636,393			
81	Orchard Tap	0			
82	Emmett Jct	27,050,335			
83	Gulch Tap	0			
84	Mountain Home AFB Tap	275,281			
85	Ontario	40,949,437			
86	King	19,258,434			
87	King	0			
88	King	0			
89	King	0			
90	Duffin	661,702			
91	American Falls	154,612			
92	Upper Salmon A-B	1,089,514			
93	Upper Salmon B	6,944,129			
94	King	26,697,329			
95	Toponis	0			
96	Boise Bench	2,450,694			
97	Quartz	3,907,344			
98	Sinker Creek Tap	318,776			
99	Mora	13,539,511			
100	Mora	0			
101	Mora	0			
102	Stoddard Jct	0			

103	Fossil Gulch Tap	273,795			
104	Wood River	9,134,622			
105	Wood River	0			
106	Oxbow	7,546,075			
107	Oxbow	0			
108	Lowell Jct	1,922,114			
109	Hunt	2,236,443			
110	Strike	1,073,775			
111	American Falls	2,395,196			
112	Pingree	1,380,518			
113	Midpoint	8,301,413			
114	Shoshone Tap	0			
115	Twin Falls	234,347			
116	Blackfoot	593,784			
117	Peterson	4,059,895			
118	Eastgate Tap	2,539,579			
119	Kimberly Tap	0			
120	Boise Bench	770,907			
121	Bowmont-Caldwell	52,366			
122	Gary Lane	2,562,658			
123	Locust Grove	5,044,724			
124	Boise Bench	1,087,836			
125	Eagle	10,715,670			
126	Star	0			
127	Beacon Light Tap	0			
128	Karcher Sub	4,094,680			
129	Zilog	0			
130	Blackcat	0			
131	Cloverdale	2,743,011			
132	Victory Jct	0			
133	Butler	1,539,907			
134	Horseflat	21,662,756			
135	Starkey	0			
136	Starkey	0			
137	Starkey	0			
138	Starkey	0			
139	Chestnut	2,300,109			
140	Garnet	40,580			
141	McCall	5,214,681			
142	McCall	0			

143	Boulder Tap	0			
144	Caldwell	6,712,211			
145	Caldwell	0			
146	Caldwell	0			
147	Willis	0			
148	Valivue Tap	351,497			
149	Raft River Tap	176			
150	Bowmont	6,737,015			
151	Antelope	162,014			
152	American Falls	105,684			
153	Bowmont	1,416,910			
154	Kinport	268,487			
155	Donn	2,470,095			
156	HOKU	0			
157	HOKU	0			
158	HOKU	0			
159	Eldridge tap	0			
160	Mora	533,011			
161	Rockland Jct	(16,973)			
162	King	60,659			
163	NorthView Tap	4,232,991			
164	Caldwell	719,019			
165	Wood River	455,241			
166	Twin Falls PP Tap	112,454			
167	American Falls PP	176,784			
168	Lower Salmon	74,560			
169	C J Strike	706,754			
170	Strike Jct	3,958,456			
171	Elmore	0			
172	Strike Jct	6,255,606			
173	Strike Jct	0			
174	Strike Jct	0			
175	Lucky Peak	331,440			
176	Bliss	1,808,965			
177	Milner Deadend	201,511			
178	Swan Falls Tap	279,752			
179	Hines	119,081			
180	69 Kv Lines	126,919,559			
181	69 Kv Lines	0			
182	46 Kv Lines	32,146,738			

183	N/A		5,624,486	2,768,690	4,602,313	12,995,489
36	TOTAL	940,213,070	5,624,486	2,768,690	4,602,313	12,995,489

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: TransmissionLineEndPoint
Borah – Midpoint - This line is jointly owned with PacifiCorp and Idaho Power owns 73.2% of this 85.4 mile line.
(b) Concept: TransmissionLineEndPoint
Summer Lake – Hemingway - This line is jointly owned with PacifiCorp and Idaho Power owns 22.0% of this 241.3 mile line.
(c) Concept: TransmissionLineEndPoint
Hemingway – Midpoint - This line is jointly owned with PacifiCorp and Idaho Power owns 37.0% of this 129.3 mile line.
(d) Concept: TransmissionLineEndPoint
Summer Lake – Hemingway - This line is jointly owned with PacifiCorp and Idaho Power owns 22.0% of this 241.3 mile line.
(e) Concept: TransmissionLineEndPoint
Hemingway – Midpoint - This line is jointly owned with PacifiCorp and Idaho Power owns 37.0% of this 129.3 mile line.
(f) Concept: TransmissionLineEndPoint
Jim Bridger – Goshen - This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this 226.6 mile line.
(g) Concept: TransmissionLineEndPoint
Kinport – Borah (Row 8) - This line is jointly owned with PacifiCorp and Idaho Power owns 73.2% of this 27.1 mile line.
(h) Concept: TransmissionLineEndPoint
Jim Bridger – Populus - This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this approximately 193 mile line.
(i) Concept: TransmissionLineEndPoint
Populus – Kinport –This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this 41.2 mile line.
(j) Concept: TransmissionLineEndPoint
Jim Bridger – Populus - This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this approximately 193 mile line.
(k) Concept: TransmissionLineEndPoint
Populus – Borah - This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this 47.3 mile line.
(l) Concept: TransmissionLineEndPoint
Goshen - Kinport - This line is jointly owned with PacifiCorp and Idaho Power owns 18.3% of this 40.9 mile line.
(m) Concept: TransmissionLineEndPoint
Midpoint – Borah #1 - This line is jointly owned with PacifiCorp and Idaho Power owns 64.4% of this 79.5 mile line.
(n) Concept: TransmissionLineEndPoint
Midpoint – Borah #2 - This line is jointly owned with PacifiCorp and Idaho Power owns 64.4% of this 77.9 mile line.
(o) Concept: TransmissionLineEndPoint
Adelaide Tap – Adelaide - This line is jointly owned with PacifiCorp and Idaho Power owns 64.4% of this 0.9 mile line.
(p) Concept: TransmissionLineEndPoint
Walla Walla - Hurricane - This line is jointly owned with PacifiCorp and Idaho Power owns 40.8% of this 77.6 mile line.
(q) Concept: TransmissionLineEndPoint
Goshen – Stateline - This line is jointly owned with PacifiCorp. Idaho Power owns 37.8% of the Goshen – Jefferson 28.9 mile segment, 37.8% of the Jefferson – Big Grassy 20.8 mile segment and 100% of the Big Grassy – Stateline 40.9 mile segment.
(r) Concept: TransmissionLineEndPoint

Antelope – Goshen - This line is jointly owned with PacifiCorp and Idaho Power owns 21.9% of this 25.8 mile line.

(s) Concept: TransmissionLineEndPoint

Goshen – Stateline - This line is jointly owned with PacifiCorp. Idaho Power owns 37.8% of the Goshen – Jefferson 28.9 mile segment, 37.8% of the Jefferson – Big Grassy 20.8 mile segment and 100% of the Big Grassy – Stateline 40.9 mile segment.

(t) Concept: TransmissionLineEndPoint

Goshen – Stateline - This line is jointly owned with PacifiCorp. Idaho Power owns 37.8% of the Goshen – Jefferson 28.9 mile segment, 37.8% of the Jefferson – Big Grassy 20.8 mile segment and 100% of the Big Grassy – Stateline 40.9 mile segment.

(u) Concept: TransmissionLineEndPoint

Antelope - Scoville - This line is jointly owned with PacifiCorp and Idaho Power owns 11.5% of this 1 mile line.

(v) Concept: TransmissionLineEndPoint

American Falls – Wheelon - This line is jointly owned with PacifiCorp and Idaho Power owns 7.2% of this 29.1 mile line.

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of 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		SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS	
	From	To	Line Length in Miles	Type	Average Number per Miles	Present	Ultimate	Size
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	GLCK	GLTP	2.5	Steel/single pole		1	1	715.5 ACSR
2	BOMT	KUTP	6.5	Steel/single pole DualCkt		2	2	1590 ACSR
3	ELMR	SWML	3	Steel/single pole DualCkt		2	2	1272 ACSR
44	TOTAL		12			5	5	

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 COST			
	From	Specification	Configuration and Spacing	Voltage KV (Operating)	Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs
	(a)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	GLCK	Stilt	TVS	138		0	0	
2	BOMT	Lapwing	DC-TAN	138		128	1,416,782	
3	ELMR	Bittern	TVS-BLP-DC	138		1,267,545	71,903	58,627
44	TOTAL					1,267,673	1,488,685	58,627

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	...	Construction
	From	Total	
	(a)	(p)	(q)
1	GLCK	0	Overground
2	BOMT	1,416,910	Overground
3	ELMR	1,398,075	Overground
44	TOTAL	2,814,985	

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

<p>(a) Concept: CostOfTransmissionLinesAdded</p> <p>Estimated amounts are reported. Construction totals include customer contribuitons</p>
<p>(b) Concept: CostOfTransmissionLinesAdded</p> <p>Estimated amounts are reported.</p>
<p>(c) Concept: CostOfTransmissionLinesAdded</p> <p>Estimated amounts are reported.</p>

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)	
1	(u) Adelaide	Transmission	Unattended	(u) 345	(u) 138	(u) 13.8	(u) 500
2	Aiken	Distribution	Unattended	46	13		27
3	Alameda	Distribution	Unattended	138	13		30
4	Alameda	Distribution	Unattended	138	13.09		30
5	American Falls PP	Transmission	Attended	138	13.8		120
6	American Falls	Transmission	Unattended	138	46	12.47	47
7	(u) Antelope	Transmission	Unattended	230	161	13.8	224
8	(u) Antelope	Transmission	Unattended	161	138	12.47	103
9	(u) Antelope	Transmission	Unattended	161	138	13.8	92
10	Artesian	Distribution	Unattended	46	13		14
11	Artesian	Distribution	Unattended	46	13.09		14
12	Bannock Creek	Distribution	Unattended	138	13		28
13	Beacon Light	Distribution	Unattended	138	13.09		45
14	Bennett Mountain Power Plant	Transmission	Attended	230	18		225
15	Bennett Mountain Power Plant	Distribution	Attended	18	4.16		5
16	Bethel Court	Distribution	Unattended	138	13		28
17	(u) Big Grassy	Transmission	Unattended	161			
18	Black Cat	Distribution	Unattended	138	13.09		90
19	Black Mesa	Distribution	Unattended	138	13		11
20	Blackfoot	Distribution	Unattended	46	13		56
21	Blackfoot	Transmission	Unattended	161	46	12.47	93
22	Blackfoot	Distribution	Unattended	161	138	12.98	

23	Blackfoot	Transmission	Unattended	161	138	12.47	18
24	Bliss	Transmission	Attended	138	13.8		86
25	Blue Gulch	Distribution	Unattended	138	35		48
26	Boise Bench	Transmission	Unattended	230	138	13.2	448
27	Boise Bench	Distribution	Unattended	138	35		30
28	Boise Bench	Transmission	Unattended	138	69	12.98	125
29	Boise Bench	Transmission	Unattended	230	138	13.8	448
30	Boise Bench	Distribution	Unattended	138	36.2		45
31	Boise	Distribution	Unattended	138	13		117
32	B Borah	Transmission	Unattended	345	230	13.8	750
33	Border	Distribution	Unattended	138	12.47		11
34	Border	Distribution	Unattended	35	12.47		5
35	Boulder	Distribution	Unattended	138	35		30
36	Bowmont	Distribution	Unattended	138	35		30
37	Bowmont	Transmission	Unattended	138	69	12.98	46
38	Bowmont	Transmission	Unattended	138	69	12.47	47
39	Bowmont	Transmission	Unattended	230	138	13.8	600
40	Brady	Transmission	Unattended	230	138	13.8	312
41	Brady	Transmission	Unattended	138	46	12.47	
42	Brady	Distribution	Unattended	46	13		
43	Brady	Distribution	Unattended	46	7.2		
44	Brownlee	Transmission	Attended	230	13.8		856
45	Bruneau Bridge	Distribution	Unattended	138	35		30
46	Bruneau Bridge	Distribution	Unattended	138	36.2		45
47	Buckhorn	Distribution	Unattended	69	35		37
48	Buhl	Distribution	Unattended	46	13.2		
49	Burley Rural	Distribution	Unattended	69	13		20
50	Burley Rural	Distribution	Unattended	69	13.09		30
51	Butler	Distribution	Unattended	138	13.09		90
52	Caldwell	Distribution	Unattended	138	13		28
53	Caldwell	Transmission	Unattended	230	138		225
54	Caldwell	Distribution	Unattended	138	13.09		45
55	Caldwell	Transmission	Unattended	138	69	12.47	140
56	Caldwell	Transmission	Unattended	230	138	12.47	200
57	Camas	Distribution	Unattended	35	12.47		5
58	Camas	Distribution	Unattended	35	14.4		10
59	Can-Ada	Distribution	Unattended	138	13.09		45
60	Canyon Creek	Distribution	Unattended	138	36.2		45
61	Canyon Creek	Transmission	Unattended	138	69	12.98	20

62	Cartwright	Distribution	Unattended	138	13		11
63	Cascade Power Plant	Transmission	Attended	69	4.6		16
64	Cascade	Distribution	Unattended	69	13.09		21
65	Cascade	Distribution	Unattended	25	12.5		5
66	Chestnut	Distribution	Unattended	138	13		45
67	Chestnut	Distribution	Unattended	138	13.09		45
68	Chip	Distribution	Unattended	230	34.5		150
69	Cinder	Distribution	Unattended	46	13		11
70	Clear Lake	Transmission	Attended	46	2.4		5
71	Cliff	Transmission	Unattended	138	46	12.5	21
72	Cliff	Transmission	Unattended	138	46	12.95	10
73	Clover	Distribution	Unattended	46	13.09		14
74	Cloverdale	Distribution	Unattended	138	13		90
75	Cloverdale	Distribution	Unattended	138	13.09		45
76	Cloverdale	Transmission	Unattended	230	138	13.8	300
77	Columbia	Distribution	Unattended	138	13.09		45
78	Council	Distribution	Unattended	69	13		14
79	Crane Creek	Distribution	Unattended	69	13		11
80	Crater	Distribution	Unattended	46	13		11
81	Dale	Distribution	Unattended	46	4.6		
82	Dale	Distribution	Unattended	46	13		
83	Dale	Distribution	Unattended	69	13		
84	Dale	Distribution	Unattended	138	36.2		90
85	Dale	Transmission	Unattended	138	46	12.47	47
86	Danskin	Transmission	Attended	230	18		233
87	Danskin	Transmission	Attended	230	138	13.8	300
88	Danskin	Distribution	Attended	18	4.16		6
89	Danskin	Transmission	Attended	138	12		160
90	Danskin	Distribution	Attended	35	13.8		5
91	Deen	Distribution	Unattended	46	13		11
92	Dietrich	Distribution	Unattended	46	13.09		14
93	Don	Distribution	Unattended	138	7.6		
94	Don	Distribution	Unattended	138	13.2		180
95	Don	Distribution	Unattended	138	13		44
96	DRAM	Distribution	Unattended	138	13.09		168
97	DRAM	Transmission	Unattended	230	138	13.8	212
98	DRAM	Distribution	Unattended	138	12.47		28
99	DRAM	Distribution	Unattended	138	13		28
100	Duffin	Distribution	Unattended	138	35		60
101	Eagle	Distribution	Unattended	138	13.09		67

102	Eastgate	Distribution	Unattended	138	13.09		75
103	Eckert	Distribution	Unattended	138	36.2		30
104	Eden	Distribution	Unattended	138	36.2		45
105	Eden	Transmission	Unattended	138	46	12.98	20
106	Eldredge	Distribution	Unattended	138	13.09		45
107	Elkhorn	Distribution	Unattended	138	12.47		11
108	Elkhorn	Distribution	Unattended	138	13		11
109	Elmore	Distribution	Unattended	138	35		28
110	Elmore	Transmission	Unattended	138	69	12.5	25
111	Elmore	Transmission	Unattended	138	69	12.98	20
112	Emmett	Distribution	Unattended	138	13.09		45
113	Emmett	Transmission	Unattended	138	69	12.47	47
114	Emmett-Boise Cascade #1	Distribution	Unattended	69	13.09		14
115	Falls	Distribution	Unattended	46	13		28
116	Filer	Distribution	Unattended	46	13		14
117	Flat Top	Distribution	Unattended	46	13		11
118	Flat Top	Distribution	Unattended	46	13.09		14
119	Flying H	Distribution	Unattended	69	2.4		20
120	Fort Hall	Distribution	Unattended	46	13		14
121	Fossil Gulch	Distribution	Unattended	138	35		28
122	Fremont	Transmission	Unattended	138	46	12.5	67
123	Fruitland	Distribution	Unattended	69	13		20
124	Gary	Distribution	Unattended	138	13.09		37
125	Gary	Distribution	Unattended	138	13		28
126	Gem	Distribution	Unattended	69	13.09		28
127	Glenns Ferry	Distribution	Unattended	138	13		11
128	Gooding Rural	Distribution	Unattended	46	13		20
129	Golden Valley	Distribution	Unattended	69	13		14
130	^(a) Goshen	Transmission	Unattended	345	161	13.8	1608
131	Gowen Substation	Distribution	Unattended	138	35		45
132	Gowen Substation	Distribution	Unattended	138	36.2		45
133	Grindstone	Distribution	Unattended	35	2.4		14
134	Grove	Distribution	Unattended	138	13.09		90
135	Grove	Distribution	Unattended	138	13		45
136	Gulch Creek	Distribution	Unattended	138	13.09		
137	Hagerman	Distribution	Unattended	46	13		14
138	Hagerman	Distribution	Unattended	69	13		6
139	Hailey	Distribution	Unattended	138	13		37
140	Happy Valley	Distribution	Unattended	138	13.09		30

141	Happy Valley	Transmission	Unattended	138	34.5	13.8	90
142	Haven	Distribution	Unattended	138	35		20
143	Haven	Transmission	Unattended	138	46		47
144	Hawk	Distribution	Unattended	138	35		30
145	^(b) Hemingway	Transmission	Unattended	500	230	34.5	1000
146	Hewlett Packard	Distribution	Unattended	138	13		37
147	Hidden Springs	Distribution	Unattended	138	13		20
148	Highland	Distribution	Unattended	138	13		30
149	Hill	Distribution	Unattended	138	13		73
150	Hillsdale	Distribution	Unattended	138	13.09		45
151	Homedale	Distribution	Unattended	69	13		34
152	Horse Flat	Transmission	Unattended	230	138	13.8	100
153	Horseshoe Bend	Distribution	Unattended	35	13.09		7
154	Horseshoe Bend	Distribution	Unattended	69	36.2		22
155	Horseshoe Bend	Distribution	Unattended	69	25		7
156	Huston	Distribution	Unattended	69	13		14
157	Hulen	Distribution	Unattended	46	13		14
158	Hunt	Transmission	Unattended	230	138	13.8	336
159	Hydra	Distribution	Unattended	138	36.2		90
160	Island	Distribution	Unattended	69	13		20
161	^(b) Jefferson	Transmission	Unattended	161			
162	Jerome	Distribution	Unattended	138	13		37
163	Jerome	Distribution	Unattended	138	13.09		37
164	Julion Clawson	Distribution	Unattended	138	36.2		45
165	Julion Clawson	Distribution	Unattended	138	34.5		45
166	Joplin	Distribution	Unattended	138	13		28
167	Joplin	Distribution	Unattended	138	36.2		45
168	Justice	Transmission	Unattended	230	138	13.8	300
169	Karcher	Distribution	Unattended	138	13		20
170	Kenyon	Distribution	Unattended	69	13.09		28
171	Ketchum	Distribution	Unattended	138	13		75
172	Kimberly	Distribution	Unattended	138	13.09		45
173	Kinport	Transmission	Unattended	161	46	13.2	
174	Kinport	Transmission	Unattended	230	138	12.47	300
175	Kinport	Transmission	Unattended	230	138	13.8	300
176	^(b) Kinport	Transmission	Unattended	345	230	13.8	1000
177	Kramer	Distribution	Unattended	138	35		20
178	Kramer	Distribution	Unattended	138	36.2		30
179	Kuna	Distribution	Unattended	138	13.09		45

180	Lake	Distribution	Unattended	69	13		14
181	Lake Fork	Distribution	Unattended	138	36.2		30
182	Lake Fork	Transmission	Unattended	138	69	12.5	20
183	Lamb	Distribution	Unattended	138	13		45
184	Langley Gulch	Transmission	Attended	230	138	13.8	636
185	Langley Gulch	Transmission	Attended	230			410
186	Langley Gulch	Transmission	Attended	230	150		
187	Langley Gulch	Distribution	Attended	18	4.16		20
188	Lansing	Distribution	Unattended	138	13.09		45
189	Lincoln	Distribution	Unattended	138	13.09		14
190	Linden	Distribution	Unattended	138	13		30
191	Linden	Distribution	Unattended	138	13.09		45
192	Locust	Distribution	Unattended	138	36.2		134
193	Locust	Transmission	Unattended	230	138	13.8	600
194	Lower Malad	Transmission	Attended	138	7.2		16
195	Lower Salmon	Transmission	Attended	138	13.8		70
196	Map Rock	Distribution	Unattended	69	13.09		14
197	McCall	Distribution	Unattended	138	13.09		22
198	McCall	Distribution	Unattended	138	36.2		30
199	Melba	Distribution	Unattended	69	13		14
200	Meridian	Distribution	Unattended	138	13		60
201	Micron	Distribution	Unattended	138	13.09		40
202	Micron	Distribution	Unattended	138	13		40
203	Midpoint	Transmission	Unattended	230	138	13.8	300
204	Midpoint	Transmission	Unattended	345	230	13.8	1400
205	^(S) Midpoint	Transmission	Unattended	500	345	34.5	1500
206	Midrose	Distribution	Unattended	138	13.09		90
207	Milner	Transmission	Unattended	138	69	12.47	125
208	Milner	Distribution	Unattended	69	46	6.9	8
209	Milner	Distribution	Unattended	138	35		50
210	Milner PP	Transmission	Attended	138	13.8		60
211	Moonstone	Distribution	Unattended	138	35		20
212	Mora	Distribution	Unattended	138	36.2		90
213	Moreland	Distribution	Unattended	46	36.2		28
214	Mountain Home	Distribution	Unattended	69	13		28
215	Mountain Home Air Force Base	Distribution	Unattended	69	13		
216	Mountain Home Air Force Base	Distribution	Unattended	138	13		34
217	Nampa	Transmission	Unattended	230	138	13.8	300

218	Nampa	Distribution	Unattended	138	13		112
219	New Meadows	Distribution	Unattended	138	36.2		22
220	New Plymouth	Distribution	Unattended	69	13.09		14
221	Northside	Distribution	Unattended	138	13		45
222	Northview	Distribution	Unattended	138	13.09		45
223	Notch Butte	Distribution	Unattended	138	13.09		14
224	Orchard	Distribution	Unattended	138	36.2		45
225	Parma	Distribution	Unattended	69	13		14
226	Parma	Distribution	Unattended	69	35		22
227	Parma	Distribution	Unattended	69	36.2		14
228	Paul	Distribution	Unattended	138	35		30
229	Paul	Distribution	Unattended	138	36.2		45
230	Payette	Distribution	Unattended	138	13.09		45
231	Pingree	Transmission	Unattended	138	46	12.5	67
232	Pingree	Distribution	Unattended	138	35		34
233	Pleasant Valley	Distribution	Unattended	138	35		30
234	Pleasant Valley	Distribution	Unattended	138	36.2		45
235	Pocatello	Distribution	Unattended	46	13		60
236	Pocket	Distribution	Unattended	138	36.2		45
237	Poleline	Distribution	Unattended	138	13.09		30
238	⁰ Populus	Transmission	Unattended	345			
239	Portneuf	Distribution	Unattended	138	35		30
240	Portneuf	Distribution	Unattended	46	35		
241	Rockford	Distribution	Unattended	46	13		25
242	Russett	Distribution	Unattended	138	13		30
243	Sailor Creek	Distribution	Unattended	138	2.4		21
244	Sailor Creek	Distribution	Unattended	138	35		28
245	Salmon	Distribution	Unattended	69	13.09		22
246	Salmon	Distribution	Unattended	69	36.2		22
247	Shoshone	Distribution	Unattended	46	13.09		14
248	Shoshone	Transmission	Unattended	138	46	12.47	47
249	Shoshone Falls	Transmission	Attended	46	4.16		4
250	Shoshone Falls	Transmission	Attended	46	6.6		14
251	Silver	Distribution	Unattended	138	35		20
252	Simplot	Distribution	Unattended	138	13		53
253	Sinker Creek	Distribution	Unattended	138	35		20
254	Siphon	Distribution	Unattended	138	36.2		75
255	Skyway	Distribution	Unattended	138	13.09		45
256	South Park	Distribution	Unattended	46	13		14

257	Spring Valley	Distribution	Unattended	138	12.47		11
258	Star	Distribution	Unattended	138	13.09		30
259	Star	Distribution	Unattended	138	13		28
260	Starkey	Transmission	Unattended	138	69	12.47	30
261	State	Distribution	Unattended	69	13		58
262	Sterling	Distribution	Unattended	46	13		11
263	Stoddard	Distribution	Unattended	138	13.09		90
264	Strike Power Plant	Transmission	Attended	138	13.8		104
265	Sugar	Distribution	Unattended	138	35		28
266	Swan Falls	Transmission	Attended	138	6.9		34
267	Tamarack	Distribution	Unattended	138	2.4		11
268	Ten Mile	Distribution	Unattended	138	13.09		90
269	Terry	Distribution	Unattended	138	13.09		20
270	Terry	Distribution	Unattended	138	13		50
271	Thousand Springs	Transmission	Attended	46	7.2		8
272	^(m) Three Mile Knoll	Transmission	Unattended	345			
273	Toponis	Distribution	Unattended	138	33		30
274	Twin Falls	Distribution	Unattended	138	13.09		82
275	Twin Falls	Transmission	Unattended	138	46	12.98	50
276	Twin Falls PP	Transmission	Attended	138	7.2		13
277	Twin Falls PP	Transmission	Attended	138	13.2		72
278	Tyhee	Distribution	Unattended	46	13		14
279	Upper Malad	Transmission	Attended	45	7.2		8
280	Upper Salmon	Transmission	Attended	138	7.2		42
281	Ustick	Distribution	Unattended	138	13		77
282	Vallivue	Distribution	Unattended	138	13.09		75
283	Victory	Distribution	Unattended	138	13		45
284	Victory	Distribution	Unattended	138	13.09		30
285	Ware	Distribution	Unattended	69	13		20
286	Weiser	Distribution	Unattended	69	13		28
287	Weiser	Transmission	Unattended	138	69	12.47	42
288	Wilder	Distribution	Unattended	69	13		14
289	Willis	Distribution	Unattended	138	13.09		75
290	Willow Creek	Distribution	Unattended	138	13		11
291	Wilson Butte	Distribution	Unattended	46	13.09		14
292	Wye	Distribution	Unattended	138	13		60
293	Wye	Distribution	Unattended	138	13.09		37
294	Zilog	Distribution	Unattended	138	13.09		45
295	The above are all State of Idaho						

296	Montana:						
297	^(w) Mill Creek	Transmission	Unattended	230			
298	Peterson	Transmission	Unattended	230	69	13.2	86
299	Nevada:						
300	^(w) Valmy	Transmission	Attended	345	18		315
301	Wells	Transmission	Unattended	138	69	13	25
302	Oregon:						
303	Adrian	Distribution	Unattended	69	13		11
304	^(w) Burns	Transmission	Unattended	500			
305	Cairo	Distribution	Unattended	69	13		20
306	Cairo	Transmission	Unattended	138	69		47
307	Hells Canyon	Transmission	Attended	230	13.8		560
308	Hells Canyon	Distribution	Attended	69	0.5		1
309	Hines	Transmission	Unattended	138	115	12.47	80
310	Halfway	Distribution	Unattended	69	13.09		14
311	Holly	Distribution	Unattended	69	13.09		14
312	Huntington	Distribution	Unattended	138	13		11
313	^(w) Hurricane	Transmission	Unattended	230			
314	Jacobson Gulch	Distribution	Unattended	69	2.4		11
315	Malheur Butte	Distribution	Unattended	69	34.5		11
316	Nyssa	Distribution	Unattended	69	13		28
317	Ontario	Distribution	Unattended	138	13		67
318	Ontario	Transmission	Unattended	138	69	12.47	47
319	Ontario	Transmission	Unattended	230	138	13.8	400
320	Ontario	Transmission	Unattended	138	69	12.98	93
321	Ontario	Transmission	Unattended	138	69	13.09	
322	Ontario	Transmission	Unattended	138	69	12.5	
323	Ore-Ida	Distribution	Unattended	69	13		28
324	Oxbow	Transmission	Attended	138	69	13	13
325	Oxbow	Transmission	Attended	230	13.8		274
326	Oxbow	Transmission	Attended	230	138	13.8	100
327	Quartz	Transmission	Unattended	138	69	12.5	25
328	Quartz	Transmission	Unattended	230	138	12.98	167
329	Quartz	Transmission	Unattended	138	69	12.98	20
330	^(w) Summer Lake	Transmission	Unattended	500			
331	Vale	Distribution	Unattended	69	13		14
332	Washington:						
333	^(s) Walla Walla	Transmission	Unattended	230			

334	Wyoming:						
335	Jim Bridger	Transmission	Attended	345	22	34.5	2244
336	Transformers-under 10,000						
337	KVA 51	Distribution	Unattended				175
339	Distribution Substation			24,117	4,202.2	19.88	7,787
340	Distribution Substation, Attended			158	26.78	0	37
341	Distribution Substation, Unattended			23,959	4,175.42	19.88	7,750
342	Generation Substation						
343	Generation Substation, Attended						
344	Generation Substation, Unattended						
345	Transmission Substation			20,330	7,724.76	942.65	22,757
346	Transmission Substation, Attended			4,944	905.26	88.9	6,998
347	Transmission Substation, Unattended			15,386	6,819.5	853.75	15,759
348	Total			44,447	11,926.96	962.53	30,544

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)
1	(a) Adelaide	2				
2	Aiken	2				
3	Alameda	1				
4	Alameda	1				
5	American Falls PP	1				
6	American Falls	1				
7	(b) Antelope	1				
8	(c) Antelope	1				
9	(d) Antelope	1				
10	Artesian	1				
11	Artesian	1				
12	Bannock Creek	1				
13	Beacon Light	1				
14	Bennett Mountain Power Plant	1				
15	Bennett Mountain Power Plant	1				
16	Bethel Court	1				
17	(e) Big Grassy					
18	Black Cat	2				
19	Black Mesa	1				
20	Blackfoot	2				
21	Blackfoot	3	1			
22	Blackfoot		1			
23	Blackfoot	1				
24	Bliss	3				
25	Blue Gulch	2				
26	Boise Bench	2				
27	Boise Bench	1				

28	Boise Bench	3				
29	Boise Bench	2				
30	Boise Bench	1				
31	Boise	3				
32	B Borah	3	1			
33	Border	1				
34	Border	3				
35	Boulder	1				
36	Bowmont	1				
37	Bowmont	1				
38	Bowmont	1				
39	Bowmont	2				
40	Brady	3				
41	Brady		1			
42	Brady		5			
43	Brady		2			
44	Brownlee	5	1			
45	Bruneau Bridge	1				
46	Bruneau Bridge	1				
47	Buckhorn	1				
48	Buhl		1			
49	Burley Rural	1				
50	Burley Rural	1				
51	Butler	2				
52	Caldwell	1				
53	Caldwell	1				
54	Caldwell	1				
55	Caldwell	3				
56	Caldwell	1				
57	Camas	3	1			
58	Camas	3	1			
59	Can-Ada	1				
60	Canyon Creek	1				
61	Canyon Creek	1				
62	Cartwright	1				
63	Cascade Power Plant	1				
64	Cascade	2				
65	Cascade	1				
66	Chestnut	1				

67	Chestnut	1				
68	Chip	1	3			
69	Cinder	1				
70	Clear Lake	1				
71	Cliff	2	1			
72	Cliff	1				
73	Clover	1				
74	Cloverdale	2				
75	Cloverdale	1				
76	Cloverdale	1				
77	Columbia	1				
78	Council	1				
79	Crane Creek	1				
80	Crater	1				
81	Dale		1			
82	Dale		4			
83	Dale		1			
84	Dale	2				
85	Dale	1				
86	Danskin	1				
87	Danskin	1				
88	Danskin	1				
89	Danskin	2				
90	Danskin	1				
91	Deen	1				
92	Dietrich	1				
93	Don		1			
94	Don	6	1			
95	Don	1				
96	DRAM	6				
97	DRAM	2				
98	DRAM	1				
99	DRAM	1				
100	Duffin	2				
101	Eagle	2				
102	Eastgate	2				
103	Eckert	1				
104	Eden	1				
105	Eden	1				
106	Eldredge	1				

107	Elkhorn	1				
108	Elkhorn	1				
109	Elmore	1				
110	Elmore	1				
111	Elmore	1				
112	Emmett	1				
113	Emmett	1				
114	Emmett-Boise Cascade #1	1				
115	Falls	2				
116	Filer	1				
117	Flat Top	1				
118	Flat Top	1				
119	Flying H	2				
120	Fort Hall	1	1			
121	Fossil Gulch	1				
122	Fremont	3	1			
123	Fruitland	1				
124	Gary	1				
125	Gary	1				
126	Gem	2				
127	Glenns Ferry	1				
128	Gooding Rural	2				
129	Golden Valley	1	1			
130	^(a) Goshen	5				
131	Gowen Substation	1				
132	Gowen Substation	1				
133	Grindstone	2				
134	Grove	2				
135	Grove	1				
136	Gulch Creek		1			
137	Hagerman	1				
138	Hagerman	1				
139	Hailey	1				
140	Happy Valley	1				
141	Happy Valley	1				
142	Haven	1				
143	Haven	1				
144	Hawk	1				
145	^(b) Hemingway	3	1			

146	Hewlett Packard	1			
147	Hidden Springs	1			
148	Highland	1			
149	Hill	2			
150	Hillsdale	1	1		
151	Homedale	2			
152	Horse Flat	1			
153	Horseshoe Bend	1			
154	Horseshoe Bend	1			
155	Horseshoe Bend	1			
156	Huston	1			
157	Hulen	1			
158	Hunt	3			
159	Hydra	2			
160	Island	1			
161	@ Jefferson				
162	Jerome	1			
163	Jerome	1			
164	Julion Clawson	1			
165	Julion Clawson	1			
166	Joplin	1			
167	Joplin	1			
168	Justice	1			
169	Karcher	1			
170	Kenyon	2			
171	Ketchum	2			
172	Kimberly	1			
173	Kinport		7		
174	Kinport	1			
175	Kinport	1			
176	@ Kinport	3	1		
177	Kramer	1			
178	Kramer	1			
179	Kuna	1			
180	Lake	1			
181	Lake Fork	1			
182	Lake Fork	1			
183	Lamb	1			
184	Langley Gulch	2			

185	Langley Gulch	2				
186	Langley Gulch		1			
187	Langley Gulch	1				
188	Lansing	1				
189	Lincoln	1				
190	Linden	1				
191	Linden	1				
192	Locust	3				
193	Locust	2				
194	Lower Malad	1				
195	Lower Salmon	4				
196	Map Rock	1				
197	McCall	1				
198	McCall	1				
199	Melba	1				
200	Meridian	2				
201	Micron	2				
202	Micron	2				
203	Midpoint	1	1			
204	Midpoint	2	1			
205	^(S) Midpoint	3	1			
206	Midrose	2				
207	Milner	3	1			
208	Milner	3	1			
209	Milner	2				
210	Milner PP	1				
211	Moonstone	1				
212	Mora	2				
213	Moreland	2				
214	Mountain Home	1				
215	Mountain Home Air Force Base		1			
216	Mountain Home Air Force Base	1				
217	Nampa	1				
218	Nampa	3				
219	New Meadows	1				
220	New Plymouth	1				
221	Northside	1				
222	Northview	1				
223	Notch Butte	1				

224	Orchard	1			
225	Parma	1			
226	Parma	1			
227	Parma	1			
228	Paul	1			
229	Paul	1			
230	Payette	1			
231	Pingree	3			
232	Pingree	2			
233	Pleasant Valley	1			
234	Pleasant Valley	1			
235	Pocatello	2			
236	Pocket	1			
237	Poleline	1			
238	Ⓜ Populus				
239	Portneuf	1			
240	Portneuf		1		
241	Rockford	2			
242	Russett	1			
243	Sailor Creek	2			
244	Sailor Creek	1			
245	Salmon	1			
246	Salmon	1			
247	Shoshone	1			
248	Shoshone	1			
249	Shoshone Falls	1			
250	Shoshone Falls	1			
251	Silver	1			
252	Simplot	2			
253	Sinker Creek	1			
254	Siphon	2			
255	Skyway	1			
256	South Park	1			
257	Spring Valley	1			
258	Star	1			
259	Star	1			
260	Starkey	1			
261	State	2			
262	Sterling	2			

263	Stoddard	2			
264	Strike Power Plant	3			
265	Sugar	2			
266	Swan Falls	1			
267	Tamarack	1			
268	Ten Mile	2			
269	Terry	1			
270	Terry	2			
271	Thousand Springs	1			
272	^(m) Three Mile Knoll				
273	Toponis	1			
274	Twin Falls	2			
275	Twin Falls	2			
276	Twin Falls PP	1			
277	Twin Falls PP	1			
278	Tyhee	1			
279	Upper Malad	1			
280	Upper Salmon	4			
281	Ustick	2			
282	Vallivue	2			
283	Victory	1			
284	Victory	1			
285	Ware	1	1		
286	Weiser	2			
287	Weiser	1			
288	Wilder	1			
289	Willis	2			
290	Willow Creek	1			
291	Wilson Butte	1			
292	Wye	2			
293	Wye	1			
294	Zilog	1			
295	The above are all State of Idaho				
296	Montana:				
297	^(o) Mill Creek				
298	Peterson	2			
299	Nevada:				
300	^(o) Valmy	1			

301	Wells	3	1		
302	Oregon:				
303	Adrian	1			
304	^(b) Burns				
305	Cairo	1			
306	Cairo	1			
307	Hells Canyon	3			
308	Hells Canyon	1			
309	Hines	1	1		
310	Halfway	1			
311	Holly	1			
312	Huntington	1			
313	^(g) Hurricane				
314	Jacobson Gulch	1			
315	Malheur Butte	3	1		
316	Nyssa	2			
317	Ontario	2			
318	Ontario	1			
319	Ontario	2			
320	Ontario	2			
321	Ontario		1		
322	Ontario		1		
323	Ore-Ida	1			
324	Oxbow	3	1		
325	Oxbow	2			
326	Oxbow	1			
327	Quartz	1			
328	Quartz	3	1		
329	Quartz	1			
330	⁽ⁱ⁾ Summer Lake				
331	Vale	1			
332	Washington:				
333	^(s) Walla Walla				
334	Wyoming:				
335	^(u) Jim Bridger	4			
336	Transformers-under 10,000				
337	KVA 51				
339	Distribution Substation	289	31	0	0

340	Distribution Substation, Attended	5	0		0	0
341	Distribution Substation, Unattended	284	31		0	0
342	Generation Substation					
343	Generation Substation, Attended				0	0
344	Generation Substation, Unattended				0	0
345	Transmission Substation	159	26		0	0
346	Transmission Substation, Attended	54	3		0	0
347	Transmission Substation, Unattended	105	23		0	0
348	Total	448	57		0	0

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: SubstationNameAndLocation
PacifiCorp has an ownership interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Adelaide station. Ownership interest varies by terminal. 100% of the capacity is reported.
(b) Concept: SubstationNameAndLocation
Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Antelope station. Ownership interest varies by terminal. 100% of the capacity is reported.
(c) Concept: SubstationNameAndLocation
Jointly owned with PacifiCorp, Idaho Power has 66.7% share of ownership. 100% of the capacity is reported.
(d) Concept: SubstationNameAndLocation
Jointly owned with PacifiCorp, Idaho Power has 66.7% share of ownership. 100% of the capacity is reported.
(e) Concept: SubstationNameAndLocation
Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Big Grassy station. Ownership interest varies by terminal.
(f) Concept: SubstationNameAndLocation
PacifiCorp has an ownership interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Borah station. Ownership interest varies by terminal. 100% of the capacity is reported.
(g) Concept: SubstationNameAndLocation
Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Goshen station. Ownership interest varies by terminal. 100% of the capacity is reported.
(h) Concept: SubstationNameAndLocation
PacifiCorp has an ownership interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Hemingway station. Ownership interest varies by terminal. 100% of the capacity is reported.
(i) Concept: SubstationNameAndLocation
Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Jefferson station. Ownership interest varies by terminal.
(j) Concept: SubstationNameAndLocation
PacifiCorp has an ownership interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Kinport station. Ownership interest varies by terminal. 100% of the capacity is reported.
(k) Concept: SubstationNameAndLocation
PacifiCorp has an ownership interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Midpoint station. Ownership interest varies by terminal. 100% of the capacity is reported.
(l) Concept: SubstationNameAndLocation
Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Populus station. Ownership interest varies by terminal.
(m) Concept: SubstationNameAndLocation
Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Three Mile Knoll station. Ownership interest varies by terminal.
(n) Concept: SubstationNameAndLocation
Idaho Power has 32% ownership in certain transmission related equipment located at Northwestern Energy's Mill Creek Station.
(o) Concept: SubstationNameAndLocation
Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership. 100% of the capacity reported.
(p) Concept: SubstationNameAndLocation

Idaho Power has a 22% ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Burns station.

(g) Concept: SubstationNameAndLocation

Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Hurricane station. Ownership interest varies by terminal.

(r) Concept: SubstationNameAndLocation

Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Summer Lake station. Ownership interest varies by terminal.

(s) Concept: SubstationNameAndLocation

Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Walla Walla station. Ownership interest varies by terminal.

(t) Concept: SubstationNameAndLocation

Jointly owned with PacifiCorp. Idaho Power has a 33.3% share of ownership. 100% of the capacity is reported.

(u) Concept: PrimaryVoltageLevel

For all of column c: Primary voltages reported in KV unless otherwise noted.

(v) Concept: SecondaryVoltageLevel

For all of column d: Secondary voltages reported in KV unless otherwise noted.

(w) Concept: TertiaryVoltageLevel

For all of column e: Tertiary voltages reported in KV unless otherwise noted.

(x) Concept: SubstationInServiceCapacity

For all of column f: Top rating capacity reported unless otherwise noted.

Name of Respondent: Idaho Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/13/2026	Year/Period of Report End of: 2025/ Q4
--	---	-------------------------------	---

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliated			
21	Managerial Expenses 417420, 417430, 417446	IDACORP, INC.	417420, 417430, 417446	441,003
22	Managerial Expenses 922000	IDACORP, INC.	922000	34,314
42				

ANNUAL REPORT
IDAHO SUPPLEMENT TO FERC FORM 1
MULTI-STATE ELECTRIC COMPANIES

INDEX

<u>Page</u> <u>Number</u>	<u>Title</u>
1	Statement of Income for the Year
2	Taxes Allocated to Idaho
3	Notes and Accounts Receivable
3	Accumulated Provision for Uncollectible Accounts
4	Receivables from Associated Companies
5	Gain or Loss on Disposition of Property
6	Professional or Consultative Services
7-10	Electric Plant in Service
11	Electric Operating Revenues
12-15	Electric Operation and Maintenance Expenses
15	Number of Electric Department Employees

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another utility column (i,k,m,o) in a similar manner to a utility department. Spread the amount(s) over lines 01 thru 24 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7, 9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1, and 407.2.
4. Use page 122 for important notes regarding the state ment of income or any account thereof.
5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year.

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL	
			Current Year (c)	Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400).....	11	\$ 1,728,008,113	\$ 1,742,559,693
3	Operating Expenses			
4	Operation Expenses (401).....	15	996,570,025	1,111,501,729
5	Maintenance Expenses (402).....	15	130,946,115	90,313,350
6	Depreciation Expense (403).....		225,322,099	205,843,291
7	Amort. & Depl. of Utility Plant (404-405).....		9,294,825	6,574,769
8	Amort. of Utility Plant Acq. Adj. (406).....			
9	Amort. of Property Losses, Unrecovered Plant and			
10	Accretion Expense (411).....		2,036	8,263
11	Regulatory Study Costs (407).....			
12	Amort. of Conversion Expenses (407).....			
13	Regulatory Debits/Credits (407.3 & 407.4).....		5,152,820	5,062,315
14	Taxes Other Than Income Taxes (408.1).....	2	26,131,864	14,316,751
15	Income Taxes - Federal (409.1).....	2	16,246,876	3,696,139
16	- Other (409.1).....	2	4,989,752	9,733,859
17	Provision for Deferred Income Taxes (410.1 & 411.1) Net.....	2	(46,756,403)	(71,263,822)
18	Investment Tax Credit Adj. - Net (411.4).....	2	43,770,106	90,653,908
19	(Less) Gains from Disp. of Utility Plant (411.6).....			
20	Losses from Disp. of Utility Plant (411.7).....			
21	(Less) Gains from Disposition of Allowances (411.8).....			
22	Losses from Disposition of Allowances (411.9).....			
23				
24	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22).....		1,411,670,116	1,466,440,552
25				
26				
27	Net Utility Operating Income (Enter Total of line 2 less 24).....		\$ 316,337,997	\$ 276,119,140

TAXES ALLOCATED TO IDAHO

<u>Kind of Tax</u>	<u>Taxes Charged During Year</u>
Taxes Other Than Income Taxes:	
Labor Related:	
FICA.....	\$ 21,684,545
FUTA.....	\$ 94,609
State Unemployment.....	335,439
Payroll Deduction & Loading.....	<u>(22,114,593)</u>
Total Labor Related.....	0
Property Taxes.....	20,894,481
Kilowatt-hour Tax.....	1,439,011
Licenses.....	4,318
Regulatory Commission Fees.....	3,570,673
Irrigation PIC.....	222,994
Nevada Commerce Tax.....	<u>386</u>
Total Taxes Other Than Income Taxes.....	<u>26,131,864</u>
Federal Income Taxes.....	16,246,876
State Income Taxes.....	4,989,752
Deferred Income Taxes.....	(46,756,403)
Investment Tax Credit Adjustment - Net.....	43,770,106
Total Taxes Allocated to Idaho.....	<u><u>\$ 44,382,195</u></u>

NOTES AND ACCOUNTS RECEIVABLE			
Summary for Balance Sheet			
Show separately by footnote the total amount of notes and accounts receivable from directors, officers, and employees included in Notes Receivable (Account 141) and Other Accounts Receivable (Account 143)			
Line No.	Accounts (a)	Balance Beginning of Year (b)	Balance End of Year (c)
1	Notes Receivable (Account 141).....	\$ -	\$ -
2	Customer Accounts Receivable (Account 142).....	119,894,558	101,497,412
3	Other Accounts Receivable (Account 143).....	19,347,044	19,731,702
4	(Disclose any capital stock subscription received)		
5	Total.....	\$ 139,241,603	\$ 121,229,115
6			
7	Less: Accumulated Provision for Uncollectible		
8	Accounts-Cr. (Account 144).....	5,698,918	4,424,709
9			
10	Total, Less Accumulated Provision for		
11	Uncollectible Accounts.....	\$ 133,542,684	\$ 116,804,405
12			
13			
14			
15			
16			
17			
18			
19			
20			

ACCUMULATED PROVISION FOR UNCOLLECTIBLE ACCOUNTS - CR. (Account 144)

1. Report below the information called for concerning this accumulated provision.
 2. Explain any important adjustments of subaccounts.
 3. Entries with respect to officers and employees shall not include items for utility services.

Line No.	Item (a)	Utility Customers (b)	Mdse, Jobbing & Contract Work (c)	Officers and Employees (d)	Other (e)	Total (f)
21	Balance Beg of Year:	\$ 5,698,918				\$ 5,698,918
22						
23	Uncollectible Retail Electric Sales	(1,282,726)	\$	\$		\$ (1,282,726)
24						
25	Uncollectible Damage Claims	8,517				\$ 8,517
26						
27	Uncollectible Other Revenues	-				\$ -
28						
29						
30						
31						
32	Balance end of year.....	\$ 4,424,709	\$ -	\$ -	\$ -	\$ 4,424,709
33						

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145, 146)

1. Report particulars of notes and accounts receivable from associated companies at end of year.
2. Provide separate headings and totals for accounts 145, Notes Receivable from Associated Companies, and 146, Accounts Receivable from Associated Companies, in addition to a total for the combined accounts.
3. For notes receivable list each note separately and state purpose for which received. Show also in column (a) date of note, date of maturity and interest rate.
4. If any note was received in satisfaction of an open account, state the period covered by such open account.
5. Include in column (f) interest recorded as income during the year, including interest on accounts and notes held at any time during the year.
6. Give particulars of any notes pledged or discounted, also of any collateral held as guarantee of payment of any note or account.

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year		Balance End of Year (e)	Interest For Year (f)
			Debits (c)	Credits (d)		
1	<u>Account 145:</u>					
2						
3	IERCO.....	\$ 14,844,151	\$ 25,814,964	\$ 26,258,179	\$ 14,400,935	
4						
5						
6						
7						
8						
9						
10	Total Account 145.....	14,844,151	25,814,964	26,258,179	14,400,935	
11						
12	<u>Account 146:</u>					
13						
14						
15						
16	IDACORP, Inc.....	\$ -	\$ 6,163,990	\$ 6,163,990	\$ -	
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31	Total Account 146.....	\$ -	\$ 6,163,990	\$ 6,163,990	\$ -	
32						

STATE OF IDAHO - TOTAL SYSTEM DATA

GAIN OR LOSS ON DISPOSITION OF PROPERTY (Account 421.1 and 421.2)

1. Give a brief description of property creating the gain or loss. Include name of party acquiring the property (when acquired by another utility or associated company) and the date transaction was completed. Identify property by type; Leased, Held for Future Use, or Nonutility.
2. Individual gains or losses relating to property with an original cost of less than \$50,000 may be grouped, with the number of such transactions disclosed in column (a).
3. Give the date of Commission approval of journal entries in column (b), when approval is required. Where approval is required but has not been received, give explanation following the item in column (a). (See account 102, Utility Plant Purchased or Sold.)

Line No.	Description of Property (a)	Original Cost of Related (b)	Date Journal Entry Approved (When Required) (c)	Acct 421.1 (d)	Acct 421.2 (e)
1	Gain on disposition of property:				
2					
3		\$ -		\$ -	
4					
5					
6					
7		\$ 0		\$ -	
8					
9					
10					
11					
12					
13					
14					
15					
16		Total gain.....	\$ -		\$ -
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31	Total loss.....	\$ 0		\$ 0	\$ 0

STATE OF IDAHO - TOTAL SYSTEM DATA

PROFESSIONAL OR CONSULTATIVE SERVICES - ITEMS \$10,000 AND OVER

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
1	ADM ASSOCIATES INC	Energy Management Consulting	81,532.50
2	BAKER BOTTS LLP	Legal Services	1,219,692.14
3	BOLD ZEBRAS, LLC	Energy Management Consulting	13,500.00
4	BROWN AND CALDWELL	Legal Services	160,767.41
5	BURNS & MCDONNELL ENGINEERING	Engineering Consultants	80,396.63
6	CASCADE ENERGY INC	Energy Management Consulting	1,272,317.07
7	CLARK WARDLE LLP	Legal Services	25,025.00
8	COMMUNITY COUNCIL OF IDAHO INC	Community Services	38,013.31
9	COMPUNET, INC	Legal Services	77,937.50
10	CORPORATE OFFICE INSTALLMENTS	Management Services	24,536.20
11	CRAVATH SWAINE AND MOORE LLP	Legal Services	97,236.37
12	CUSHMAN & WAKEFIELD OF NORTH C	Real Estate Services	174,679.27
13	DAY PITNEY LLP	Legal Services	26,530.00
14	DELOITTE TAX LLP	Management Services	12,450.00
15	DONNELLEY FINANCIAL SOLUTIONS	Risk and Compliance Software	64,771.00
16	EL-ADA COMMUNITY ACTION A	Community Services	42,397.76
17	ELAM AND BURKE PA	Legal Services	16,094.18
18	ENERGY350	Energy Management Consulting	967,308.09
19	EQ SHAREOWNER SERVICES	Management Services	100,439.66
20	EVERGREEN CONSULTING GROUP, LL	Management Services	481,901.17
21	EXPONENT, INC	Analysis Services	73,626.72
22	FRESHWATER TRUST, THE	Enviornmental Services	2,100,000.00
23	GIVENS PURSLEY LLP	Legal Services	629,661.25
24	GREENBERG TRAUIG LLP	Legal Services	15,231.00
25	HARRINGTON LEGAL SERVICES PLLC	Legal Services	149,040.00
26	HAWLEY TROXELL ENNIS & HAWLEY	Legal Services	42,230.42
27	HDR ENGINEERING, INC	Engineering Consultants	108,317.71
28	HOLLAND & HART LLP	Legal Services	63,669.00
29	IDAH20 PLLC	Legal Services	143,006.70
30	ITRON, INC.	Technical Services	10,110.84
31	J J KELLER & ASSOCIATES INC.	Management Services	10,000.00
32	JACKSON LEWIS PC	Legal Services	11,007.00
33	JENSEN HUGHES	Safety Consulting Services	32,753.68
34	JONES WILLIAMS FUHRMAN GOURLEY	Legal Services	37,736.63
35	KELLER AND HECKMAN LLP	Legal Services	45,447.50
36	KIRTON MCCONKIE	Legal Services	224,056.83
37	KW ENGINEERING INC	Engineering Consultants	385,007.43
38	L & R GROUP LLC, THE	Enviornmental Services Consulting	15,691.19
39	MAKO PROFESSIONALS LLC	Technical Services	42,997.00
40	MARKOWITZ HERBOLD P C	Legal Services	45,690.39
41	MARTEN LAW LLP	Legal Services	140,025.40
42	MCDOWELL RACKNER & GIBSON PC	Legal Services	555,312.33
43	MCNIVEN STRATEGIES INC	Risk and Compliance Software	31,500.00
44	MEDIANT COMMUNICATIONS INC	Management Services	32,484.38

STATE OF IDAHO - TOTAL SYSTEM DATA

PROFESSIONAL OR CONSULTATIVE SERVICES - ITEMS \$10,000 AND OVER

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
45	MERCER THOMPSON LLC	Legal Services	318,378.26
46	MOODYS ANALYTICS INC	Technical Services	47,244.00
47	NELSON, WILLIAMS, CALLAHAN & P	Legal Services	32,467.63
48	NEW YORK STOCK EXCHANGE I	Management Services	118,066.00
49	PARSONS BEHLE & LATIMER	Legal Services	268,140.00
50	PERKINS COIE LLP	Legal Services	995,864.94
51	POWER ENGINEERS INC	Engineering Consultants	741,545.60
52	PRODUCTIVE ENERGY SOLUTIONS LL	Energy Management Consulting	14,991.39
53	PROFESSIONAL INSPECTION SERVIC	Management Services	90,573.05
54	ROCK CREEK ENERGY GROUP LLP	Legal Services	45,797.60
55	SCHWABE WILLIAMSON & WYATT	Legal Services	56,335.24
56	SEG CE	Management Services	12,458.83
57	SNELL & WILMER LLP	Legal Services	17,467.00
58	SOUTH CENTRAL COMMUNITY ACTION	Community Services	20,905.39
59	SOUTHEASTERN IDAHO COMMUNITY	Community Services	10,764.52
60	STOEL RIVES LLP	Legal Services	58,189.46
61	STRATEGIC ENERGY GROUP	Energy Management Consulting	152,958.13
62	TETRATECH	Analysis Services	27,345.00
63	THE LAKE FOREST GROUP	Safety Consulting Services	18,750.00
64	THOMPSON ADVISORY LLC	Legal Services	22,193.75
65	TRC ENVIORNMENTAL CORPORATION	Engineering Consultants	135,065.36
66	UNIVERSITY OF IDAHO	Agricultural Services	317,232.55
67	VALBRIDGE PROPERTY ADVISORS	Real Estate Services	65,275.00
68	VAN NESS FELDMAN LLP	Legal Services	530,652.34
69	WASTELINQ INC	Energy Management Consulting	11,799.25
70	WILLIS TOWERS WATSON US LLC	Legal Services	14,820.00
71	WINNER MANAGEMENT INC	Real Estate Services	13,574.25
72	WITHERSPOON BRAJCICH MCPHEE PL	Legal Services	31,654.50
73	YTURRI ROSE LLP	Legal Services	1,458,957.96
74			
75			
76			
77			
78			
79			
80			
81			
82			
83			
	TOTAL		\$ 15,571,596

PROFESSIONAL OR CONSULTATIVE SERVICES			
<u>ITEMS \$5,000 OR MORE BUT LESS THAN \$10,000</u>			
Line No.	PAYEE	PREDOMINANT NATURE OF SERVICE	AMOUNT
1	ABBEY LOUIE LLC	Management Services	7,500.00
2	AUTOSORT	Management Services	9,857.82
3	CCRCORP	Legal Services	7,335.00
4	COMMUNITY IN ACTION	Community Services	7,140.00
5	CRAPO DEEDS PLLC	Legal Services	9,379.50
6	DAVIS WRIGHT TREMAINE LLP	Legal Services	7,397.50
7	EXPRESS SERVICES INC	Management Services	5,400.00
8	HOME ENERGY EFFICIENCY TECHNOL	Energy Management Consulting	8,988.50
9	J J KELLER & ASSOCIATES INC	Management Services	10,000.00
10	MARSH USA INC	Risk and Compliance Consulting	8,902.67
11	MLCHOATE INC	Training Services	6,250.00
12	MORROW & FISCHER PLLC	Legal Services	7,000.31
13	NEEC	Engineering Consultants	6,250.00
14	NICE SYSTEMS INC	Technical Services	8,145.00
15	NORTHWEST ENERGY EFFICIENCY CO	Energy Management Consulting	6,300.00
16	PROFESSIONAL TRAINING SYSTEMS	Training Services	7,168.87
17	SMITH + MALEK PLLC	Legal Services	6,337.50
18	SOLARC ENERGY GROUP LLC	Energy Management Consulting	5,297.65
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43	TOTAL		\$ 134,650.32

ELECTRIC PLANT IN SERVICE (Accounts 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. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. 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 prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements 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) reversals of tentative distributions of prior year of unclassified retirements. Attach supplemental statement showing the account 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.

Line No.	Account (a)	Beginning of year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization.....	\$ 5,461	
3	(302) Franchises and Consents.....	59,559,761	
4	(303) Miscellaneous Intangible Plant.....	83,153,219	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4).....	142,718,441	
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights.....		
9	(311) Structures and Improvements.....		
10	(312) Boiler Plant Equipment.....		
11	(313) Engines and Engine Driven Generators.....		
12	(314) Turbogenerator Units.....		
13	(315) Accessory Electric Equipment.....		
14	(316) Misc. Power Plant Equipment.....		
15	(317) Asset Retirement Costs for Steam Production.....		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15).....	963,754,520	
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights.....		
19	(321) Structures and Improvements.....		
20	(322) Reactor Plant Equipment.....		
21	(323) Turbogenerator Units.....		
22	(324) Accessory Electric Equipment.....		
23	(325) Misc. Power Plant Equipment.....		
24	(326) Asset Retirement Costs for Nuclear Production.....		
25	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 24).....		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights.....		
28			
29	(332) Reservoirs, Dams, and Waterways.....		
30	(333) Water Wheels, Turbines, and Generators.....		
31	(334) Accessory Electric Equipment.....		
32	(335) Misc. Power Plant Equipment.....		
33	(336) Roads, Railroads, and Bridges.....		
34	(337) Asset Retirement Costs for Hydraulic Production.....		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34).....	1,136,709,802	
36	D. Solar Production Plant		
37	(338) Solar Production Plant	-	
38	TOTAL Solar Production Plant (Enter Total of line 37).....		
39	E. Other Production Plant		
40	(340) Land and Land Rights.....		
41	(341) Structures and Improvements.....		
42	(342) Fuel Holders, Products and Accessories.....		
43	(343) Prime Movers.....		
44	(344) Generators.....		
45	(345) Accessory Electric Equipment.....		
46	(346) Misc Power Plant Equipment.....		

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103 and 106) (Continued)

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. In showing the clearance of 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.

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 requirements of these pages.

For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, 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 of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	End of Year (g)		Line No.
			\$ 5,458	(301)	1
			\$ 61,924,253	(302)	2
			\$ 3,404,729	(303)	3
			65,334,439		4
					5
					6
				(310)	7
				(311)	8
				(312)	9
				(313)	10
				(314)	11
				(315)	12
				(316)	13
			14,226,931	(317)	14
			774,041,414		15
					16
				(320)	17
				(321)	18
				(322)	19
				(323)	20
				(324)	21
				(325)	22
				(326)	23
					24
					25
				(330)	26
				(331)	27
				(332)	28
				(333)	29
				(334)	30
				(335)	31
				(336)	32
				(337)	33
			1,189,090,011		34
					35
			100,698	(338)	36
					37
					38
					39
				(340)	40
				(341)	41
				(342)	42
				(343)	43
				(344)	44
				(345)	45
				(345)	46

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103 and 106) (Continued)			
Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)
47	(346) Misc. Power Plant Equipment.....		
48	TOTAL Other Production Plant (Enter Total of lines 37 thru 44).....	\$ 608,520,303	
49	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45).....	2,708,984,625	
50	3. TRANSMISSION PLANT		
51	(350) Land and Land Rights.....	42,219,406	
52	(351) Computer Hardware/Software/Communication Equipment.....		
53	(352) Structures and Improvements.....	124,210,128	
54	(353) Station Equipment.....	503,245,628	
55	(354) Towers and Fixtures.....	250,321,545	
56	(355) Poles and Fixtures.....	255,803,844	
57	(356) Overhead Conductors and Devices.....	298,268,736	
58	(357) Underground Conduit.....		
59	(358) Underground Conductors and Devices.....		
60	(359) Roads and Trails.....	389,291	
61	(359.1) Asset Retirement Costs for Transmission Plant.....		
62	TOTAL Transmission Plant (Enter Total of lines 51 thru 61).....	1,474,458,577	
63	4. DISTRIBUTION PLANT		
64	(360) Land and Land Rights.....	10,299,254	
65	(361) Structures and Improvements.....	66,947,216	
66	(362) Station Equipment.....	354,681,402	
67	(363.1-3) Computer Hardware/Software/Communication Equipment.....		
68	(364) Poles, Towers, and Fixtures.....	337,960,920	
69	(365) Overhead Conductors and Devices.....	163,968,083	
70	(366) Underground Conduit.....	58,927,984	
71	(367) Underground Conductors and Devices.....	359,904,425	
72	(368) Line Transformers.....	785,463,052	
73	(369) Services.....	71,635,700	
74	(370) Meters.....	122,879,963	
75	(371) Installations on Customer Premises.....	5,195,270	
76	(372) Leased Property on Customer Premises.....		
77	(373) Street Lighting and Signal Systems.....	6,563,857	
78	(374) Asset Retirement Costs for Distribution Plant.....		
79	TOTAL Distribution Plant (Enter Total of lines 60 thru 74).....	2,344,427,126	
80	5. ENERGY STORAGE PLANT		
81	(387) Energy Storage Plant.....	377,683,182	
82	TOTAL Energy Storage Plant (Enter Total of line 80).....		
83	6. GENERAL PLANT		
84	(389) Land and Land Rights.....	20,182,016	
85	(390) Structures and Improvements.....	177,825,871	
86	(391) Office Furniture and Equipment.....	41,548,293	
87	(392) Transportation Equipment.....	134,135,649	
88	(393) Stores Equipment.....	9,007,503	
89	(394) Tools, Shop, and Garage Equipment.....	15,796,680	
90	(395) Laboratory Equipment.....	15,868,521	
91	(396) Power Operated Equipment.....	31,317,791	
92	(397.1-3) Computer Hardware/Software/Communication Equipment.....	80,955,258	
93	(398) Miscellaneous Equipment.....	10,444,653	
94	SUBTOTAL (Enter Total of lines 84 thru 93).....	537,082,234	
95	(399) Other Tangible Property.....		
96	(399.1) Asset Retirement Costs for General Plant.....		
97	TOTAL General Plant (Enter Total of lines 94, 95 and 96).....	537,082,234	
98	TOTAL (Accounts 101 and 106).....	7,207,671,003	
99	(102) Electric Plant Purchased		
100			
101	TOTAL Electric Plant in Service.....	\$ 7,207,671,003	

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103 and 106) (Continued)					
Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
				(346)	47
			\$ 610,482,107		48
			2,573,714,229		49
			43,657,291	(350)	50
			23,128,317	(351)	51
			145,562,629	(352)	52
			513,592,447	(353)	53
			263,391,511	(354)	54
			270,810,957	(355)	55
			329,859,653	(356)	56
				(357)	57
				(358)	58
			389,655	(359)	59
				(359.1)	60
			1,590,392,460		61
					62
			11,011,899	(360)	63
			68,248,821	(361)	64
			385,411,749	(362)	65
			20,839,806	(363)	66
			371,797,095	(364)	67
			172,888,830	(365)	68
			62,258,574	(366)	69
			377,615,719	(367)	70
			837,519,247	(368)	71
			74,668,019	(369)	72
			127,830,430	(370)	73
			4,332,604	(371)	74
				(372)	75
			6,316,981	(373)	76
				(374)	77
			2,520,739,773		78
					79
			490,316,377	(387)	80
					81
					82
			20,313,183	(389)	83
			192,480,764	(390)	84
			13,433,467	(391)	85
			153,105,935	(392)	86
			10,259,460	(393)	87
			16,373,845	(394)	88
			15,951,748	(395)	89
			32,579,835	(396)	90
			194,494,268	(397)	91
			12,209,453	(398)	92
			661,201,957		93
					94
				(399)	95
				(399.1)	96
			661,201,957		97
			7,901,699,235		98
				(102)	99
					100
			\$ 7,901,699,235		101

ELECTRIC OPERATING REVENUES (Account 400)			
<p>1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.</p> <p>2. 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.</p> <p>3. If previous year (columns (c), (e) and (g), are not derived from previously reported figures, explain any inconsistencies in a footnote.</p>			
No.	(a)	OPERATING REVENUES	
		Amount for Current Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales.....	\$ 686,214,285	\$ 679,349,973
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)(See Instr. 4) (1).....	563,514,068	565,843,191
5	Large (or Industrial)(See Instr. 4) (2).....	251,068,344	247,393,895
6	(444) Public Street and Highway Lighting.....	4,350,649	4,192,970
7	(445) Other Sales to Public Authorities.....		
8	(446) Sales to Railroads and Railways.....		
9	(448) Interdepartmental Sales.....		
10	TOTAL Sales to Ultimate Consumers.....	1,505,147,346 *	1,496,780,029
11	(447) Sales for Resale - Opportunity...Non-Firm Only.....	119,415,541	136,721,592
12	TOTAL Sales of Electricity.....	1,624,562,887	1,633,501,621
13	(449) Provision for Rate Refunds.....	(15,119,961)	(8,803,453)
14	TOTAL Revenue Net of Provision for Refunds.....	1,609,442,925	1,624,698,168
15	Other Operating Revenues		
16	(450) Forfeited Discounts.....		
17	(451) Miscellaneous Service Revenues.....	7,191,360	6,752,488
18	(453) Sales of Water and Water Power.....		
19	(454) Rent from Electric Property.....	21,008,860	18,605,194
20	(455) Interdepartmental Rents.....		
21	(456) Other Electric Revenues.....	90,364,967	92,503,842
22			
23			
24			
25	TOTAL Other Operating Revenues.....	118,565,187	117,861,524
26	TOTAL Electric Operating Revenues.....	\$ 1,728,008,113	\$ 1,742,559,693

(1) Commercial and Industrial sales - Small - under 1,000 KW and includes all irrigation customers.
(2) Commercial and Industrial sales - Large - 1,000 KW and over.

ELECTRIC OPERATING REVENUES (Account 400) (Continued)

- 4. 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
- 5. See page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.
- 6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts.
- 7. Include unmetered sales. Provide details of such sales in a footnote.

KILOWATT HOURS SOLD		AVERAGE NUMBER OF CUSTOMERS PER MONTH		Line No.
Amount for Current Year (d)	Amount for Previous Year (e)	Amount for Current Year (f)	Number for Previous Year (g)	
5,826,203,969	5,777,153,324	540,032	525,751	1
6,131,471,240	6,072,267,477	91,584	90,596	2
3,521,803,924	3,423,421,169	143	132	3
24,889,792	24,253,516	5,190	4,893	4
				5
				6
				7
				8
				9
15,504,368,925 **	15,297,095,486	636,949	621,372	10
<u>2,777,376,052</u>	2,699,974,813	N/A	N/A	11
18,281,744,977	17,997,070,299	636,949	621,372	12
				13

* Includes - \$10,018,543.00 in unbilled revenues.

** Includes -31,960,058 KWH relating to unbilled revenues.

Lines 11 through 21 are on an "allocated" basis.

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
If the amount for previous year is not derived from previously reported figures, explain in footnotes.			
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.....	\$ 1,783,332	\$ 917,286
5	(501) Fuel.....	\$ 111,154,595	93,364,798
6	(502) Steam Expenses.....	\$ 5,845,656	8,487,527
7	(503) Steam from Other Sources.....		
8	(Less) (504) Steam Transferred-Cr.....		
9	(505) Electric Expenses.....	790,263	1,679,479
10	(506) Miscellaneous Steam Power Expenses.....	7,511,938	7,714,259
11	(507) Rents.....	194,650	215,101
12	(509) Allowances.....		
13	TOTAL Operation (Enter Total of lines 4 thru 12).....	127,280,434	112,378,451
14	Maintenance		
15	(510) Maintenance Supervision and Engineering.....	169,536	50,799
16	(511) Maintenance of Structures.....	245,954	341,856
17	(512) Maintenance of Boiler Plant.....	7,759,684	8,166,195
18	(513) Maintenance of Electric Plant.....	3,281,699	3,021,135
19	(514) Miscellaneous Steam Plant.....	9,198,072	7,171,478
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19).....	20,654,945	18,751,464
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20).....	147,935,379	131,129,914
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering.....		
25	(518) Fuel.....		
26	(519) Coolants and Water.....		
27	(520) Steam Expenses.....		
28	(521) Steam from Other Sources.....		
29	(Less) (522) Steam Transferred-Cr.....		
30	(523) Electric Expenses.....		
31	(524) Miscellaneous Nuclear Power Expenses.....		
32	(525) Rents.....		
33	TOTAL Operation (Enter Total of lines 24 thru 32).....		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering.....		
36	(529) Maintenance of Structures.....		
37	(530) Maintenance of Reactor Plant Equipment.....		
38	(531) Maintenance of Electric Plant.....		
39	(532) Maintenance of Miscellaneous Nuclear Plant.....		
40			
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 and 40).....		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering.....	5,456,139	5,966,403
45	(536) Water for Power.....	3,329,688	2,796,621
46	(537) Hydraulic Expenses.....	20,641,719	20,410,497
47	(538) Electric Expenses.....	2,147,210	2,224,435
48	(539) Miscellaneous Hydraulic Power Generation Expenses.....	6,090,102	6,322,777
49	(540) Rents.....	310,431	306,643
50	TOTAL Operation (Enter Total of lines 44 thru 49).....	37,975,289	38,027,375

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
If the amount for previous year is not derived from previously reported figures, explain in footnotes.			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering.....	\$ 3,800	\$ 172,728
54	(542) Maintenance of Structures.....	1,084,378	1,106,792
55	(543) Maintenance of Reservoirs, Dams, and Waterways.....	661,132	1,654,211
56	(544) Maintenance of Electric Plant.....	3,989,005	3,634,976
57	(545) Maintenance of Miscellaneous Hydraulic Plant.....	5,540,635	4,938,662
58	TOTAL Maintenance (Enter Total of lines 53 thru 57).....	11,278,950	11,507,370
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 59)	49,254,240	49,534,745
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering.....	522,560	572,978
63	(547) Fuel.....	131,663,061	155,031,812
64	(548) Generation Expenses.....	5,405,904	5,997,354
65	(549) Miscellaneous Other Power Generation Expenses.....	457,047	700,640
66	(550) Rents.....	0	0
67	TOTAL Operation (Enter Total of lines 62 thru 66).....	138,048,573	162,302,784
68	Maintenance		
69	(551) Maintenance Supervision and Engineering.....	139,249	0
70	(552) Maintenance of Structures.....	155,537	97,764
71	(553) Maintenance of Generating and Electric Plant.....	602,545	105,354
72	(554) Maintenance of Miscellaneous Other Power Generation Plant.....	3,925,328	3,098,034
73	TOTAL Maintenance (Enter Total of lines 69 thru 72).....	4,822,659	3,301,151
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	142,871,232	165,603,935
75	E. Other Power Supply Expenses		
76	(555) Purchased Power.....	365,523,438	394,793,124
77	(556) System Control and Load Dispatching.....	0	81
78	(557) Other Expenses.....	21,001,874	81,047,102
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78).....	386,525,312	475,840,307
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	726,586,162	822,108,902
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering.....	1,196,740	2,696,337
84	(561) Load Dispatching.....	5,081,503	4,899,012
85	(562) Station Expenses.....	1,583,258	2,488,101
86	(563) Overhead Line Expenses.....	1,135,924	1,200,862
87	(564) Underground Line Expenses.....	0	12,565,463
88	(565) Transmission of Electricity by Others.....	10,791,052	0
89	(566) Miscellaneous Transmission Expenses.....	0	4,351,143
90	(567) Rents.....	4,426,688	0
91	TOTAL Operation (Enter Total of lines 83 thru 90).....	24,215,164	28,200,918
92	Maintenance		
93	(568) Maintenance Supervision and Engineering.....	125,282	452,204
94	(569) Maintenance of Structures.....	2,726,748	1,637,271
95	(570) Maintenance of Station Equipment.....	2,291,980	3,067,734
96	(571) Maintenance of Overhead Lines.....	2,535,832	4,023,390
97	(572) Maintenance of Underground Lines.....		
98	(573) Maintenance of Miscellaneous Transmission Plant.....	1,900	730
99	(575) Transmission Market Administration - EIM.....	630,879	531,114
99	TOTAL Maintenance (Enter Total of lines 93 thru 98).....	8,312,620	9,712,443
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99).....	32,527,785	37,913,361
101	3. BATTERY STORAGE EXPENSES		
102	(577) Battery Storage Expense	12,819,496	0
103	TOTAL Operation (Enter Total of line 102).....	12,819,496	0
104	(578) Maintenance of Energy Storage	1,178,041	0
105	TOTAL Maintenance (Enter Total of line 104).....	1,178,041	0
106	TOTAL Battery Storage Expenses (Enter Total of lines 103 and 105).....	13,997,537	0
106	4. DISTRIBUTION EXPENSES		
107	Operation		
108	(580) Operation Supervision and Engineering.....	4,305,870	4,744,192

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
If the amount for previous year is not derived from previously reported figures, explain in footnotes.			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
109	4. DISTRIBUTION EXPENSES (Continued)		
110	(581) Load Dispatching.....	\$ 5,910,211	\$ 5,772,694
111	(582) Station Expenses.....	1,883,006	1,874,227
112	(583) Overhead Line Expenses.....	6,030,098	6,159,648
113	(584) Underground Line Expenses.....	6,829,025	5,900,362
114	(585) Street Lighting and Signal System Expenses.....	-	179
115	(586) Meter Expenses.....	6,602,485	6,649,774
116	(587) Customer Installations Expenses.....	1,114,798	1,172,110
117	(588) Miscellaneous Distribution Expenses.....	4,195,901	4,181,704
118	(589) Rents.....	515,772	384,380
119	TOTAL Operation (Enter Total of lines 103 thru 113).....	37,387,166	36,839,271
120	Maintenance		
121	(590) Maintenance Supervision and Engineering.....	5,085	8,683
122	(591) Maintenance of Structures.....	9,794	0
123	(592) Maintenance of Station Equipment.....	6,784,489	5,119,959
124	(593) Maintenance of Overhead Lines.....	33,988,776	32,768,450
125	(594) Maintenance of Underground Lines.....	566,830	969,729
126	(595) Maintenance of Line Transformers.....	64,433	56,554
127	(596) Maintenance of Street Lighting and Signal Systems.....	171,918	191,606
128	(597) Maintenance of Meters.....	1,077,076	986,476
129	(598) Maintenance of Miscellaneous Distribution Plant.....	246,077	204,411
130	TOTAL Maintenance (Enter Total of lines 116 thru 124).....	42,914,478	40,305,868
131	TOTAL Distribution Expenses (Enter Total of lines 114 and 125).....	80,301,644	77,145,139
132	5. CUSTOMER ACCOUNTS EXPENSES		
133	Operation		
134	(901) Supervision.....	896,393	879,377
135	(902) Meter Reading Expenses.....	1,541,943	1,827,516
136	(903) Customer Records and Collection Expenses.....	14,627,642	16,754,501
137	(904) Uncollectible Accounts.....	2,808,960	4,304,018
138	(905) Miscellaneous Customer Accounts Expenses.....	(57)	10
139	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133).....	19,874,881	23,765,422
140	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
141	Operation		
142	(907) Supervision.....	1,267,224	1,108,718
143	(908) Customer Assistance Expenses.....	38,728,140	35,699,257
144	(909) Informational and Instructional Expenses.....	250,996	332,225
145	(910) Miscellaneous Customer Service and Informational Expenses.....	725,469	697,499
146	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 145).....	40,971,830	37,837,699
147	7. SALES EXPENSES		
148	Operation		
149	(911) Supervision.....	-	-
150	(912) Demonstrating and Selling Expenses.....	0	-
151	(913) Advertising Expenses.....		
152	(916) Miscellaneous Sales Expenses.....		
153	TOTAL Sales Expenses (Enter Total of lines 144 thru 147).....	-	-
154	8. ADMINISTRATIVE AND GENERAL EXPENSES		
155	Operation		
156	(920) Administrative and General Salaries.....	90,782,114	105,373,951
157	(921) Office Supplies and Expenses.....	8,865,438	18,472,902
158	(Less) (922) Administrative Expenses Transferred-Credit.....	(38,871,893)	(45,450,827)

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
If the amount for previous year is not derived from previously reported figures, explain in footnotes.			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
159	9. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
160	(923) Outside Services Employed.....	\$ 7,700,517	\$ 10,223,065
161	(924) Property Insurance.....	4,853,608	4,847,466
162	(925) Injuries and Damages.....	10,833,806	10,142,906
163	(926) Employee Pensions and Benefits.....	74,991,514	81,413,144
164	(927) Franchise Requirements.....	0	0
165	(928) Regulatory Commission Expenses.....	6,743,412	6,153,860
166	(929) Duplicate Charges-Cr.....		
167	(930.1) General Advertising Expenses.....	182,355	127,535
168	(930.2) Miscellaneous General Expenses.....	4,760,130	4,474,387
169	(931) Rents.....	0	0
170	TOTAL Operation (Enter Total of lines 151 thru 164).....	170,841,001	195,778,388
171	Maintenance		
172	(935) Maintenance of General Plant.....	42,415,300	7,266,169
173	TOTAL Admin and General Expenses (Enter Total of lines 165-167).....	213,256,301	203,044,556
174	TOTAL Elec Op and Maint Exp (Total of 80, 100, 126, 134, 141, 148, 168).....	\$ 1,127,516,140	\$ 1,201,815,079

IDAHO ONLY

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES		
<p>1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.</p> <p>2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.</p> <p>3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.</p>		
	December 31, 2025	December 31, 2024
1	Payroll Period Ended (Date).....	
2	Total Regular Full-Time Employees.....	2,166 2,122
3	Total Part-Time and Temporary Employees.....	8 8
4	Total Employees.....	2,174 2,130