e-FILING REPORT COVER SHEET

REPORT NAME: 2016 FERC Form 1 and Annual Report

COMPANY NAME: Idaho Power Company

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes

If yes, please submit only the cover letter electronically. Submit confidential information as directed OAR 860-001-0070 or the terms of an applicable protective order.

If known, please select designation: ☒ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RO (Other)

Report is required by: ☒ OAR 860-027-0070
☐ Statute
☐ Order
☐ Other

Is this report associated with a specific docket/case? ☒ No ☐ Yes

If Yes, enter docket number:

Key words:

If known, please select the PUC Section to which the report should be directed:

☐ Corporate Analysis and Water Regulation

☐ Economic and Policy Analysis

☐ Electric and Natural Gas Revenue Requirements

☐ Electric Rates and Planning

☐ Natural Gas Rates and Planning

☐ Utility Safety, Reliability & Security

☐ Administrative Hearings Division

☐ Consumer Services Section

PLEASE NOTE: Do NOT use this form or e-filing with the PUC Filing Center for:

- **Annual Fee Statement form and payment remittance or**
- **OUS or RSPF Surcharge form or surcharge remittance or**
- **Any other Telecommunications Reporting or**
- **Any daily safety or safety incident reports or**
- **Accident reports required by ORS 654.715.**

LISA D. NORDSTROM
Lead Counsel
lnordstrom@idahopower.com

April 27, 2017

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97301

Re: Idaho Power Company's 2016 Annual FERC Form 1 Report

Attention Filing Center:

As required by OAR 860-027-0070, Idaho Power Company herewith transmits for electronic filing its FERC Form 1 report and Oregon supplement for the year ending December 31, 2016. Also included is the IDACORP 2016 Annual Report.

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

Very truly yours,

Lisa D. Nordstrom

Lisa D. Nordstrom

LDN:kkt

Enclosures

THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Idaho Power Company	**End of** 2016/Q4

THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Idaho Power Company	**End of** 2016/Q4

Deloitte.

Deloitte & Touche LLP
800 West Main Street
Suite 1400
Boise, ID 83702-7734
USA

Tel: +1 208 342 9361
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

Idaho Power Company
Boise, Idaho

We have audited the accompanying financial statements of Idaho Power Company (the "Company"), which comprise the balance sheet—regulatory basis as of December 31, 2016, and the related statements of income—regulatory basis, retained earnings—regulatory basis, and cash flows—regulatory basis for the year then ended, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the regulatory-basis financial statements referred to above present fairly, in all material respects, the assets, liabilities, and proprietary capital of Idaho Power Company as of December 31, 2016, and the results of its operations and its cash flows for the year then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

Basis of Accounting

We draw attention to Note 1 of the financial statements, which describes the basis of accounting. The financial statements are prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a basis of accounting other than accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Restriction on Use

Our report is intended solely for the information and use of the board of directors and management of the Company and for filing with the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte & Touche LLP

April 14, 2017

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FERC FORM NO. 1/3-Q:
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 2016/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 Ken Petersen	06 Title of Contact Person VP, Controller and CAO
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) 388-2761	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 04/14/2017

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 Ken Petersen 02 Title Vice President, Controller & CAO	03 Signature Ken Petersen	04 Date Signed *(Mo, Da, Yr)* 04/14/2017

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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".

LIST OF SCHEDULES (Electric Utility) (continued)

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".

LIST OF SCHEDULES (Electric Utility) (continued)

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".

Stockholders' Reports Check appropriate box:

- [ ] Two copies will be submitted
- [ ] No annual report to stockholders is prepared

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Ken Petersen Vice President, Controller and CAO, Idaho Power Company
1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070

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.

Idaho, June 30, 1989

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.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Class of Utility Service	State
Electric	Idaho
Electric	Oregon

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent 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 beneficieraries for whom trust was maintained, and purpose of the trust.

Idaho Power Company is a subsidiary of IDACORP, INC

IDACORP owns 100% of Idaho Power Company's Common Stock.

IDACORP is a public utility Holding Company incorporated effective 10-1-1998

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		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	President & Chief Executive Officer	Darrel T. Anderson	750,000
3			
4	Executive Vice President	Dan Minor (1)	245,923
5			
6	Senior Vice President	Rex Blackburn (2)	360,000
7			
8	Senior Vice President, CFO & Treasurer	Steven Keen	380,000
9			
10	Senior Vice President, Operations	Lisa Grow	360,000
11			
12	Senior Vice President, Public Affairs	Jeffrey Malmen	285,000
13			
14	Vice President, Customer Operations	Vern Porter	285,000
15			
16	Senior Vice President, Human Resources, Admin Services	Lonnie Krawl	275,000
17			
18	Vice President & Chief Risk Officer	Lori Smith (3)	70,846
19			
20	Vice President, Corporate Controller & CAO	Ken Petersen	245,000
21			
22	Vice President of Regulatory Affairs	Gregory Said (4)	81,904
23			
24	Corporate Secretary	Patrick Harrington	195,000
25			
26	Vice President, Power Supply	Tessia Park	220,000
27			
28	Vice President & General Counsel	Brian Buckham	230,000
29			
30	Vice President of Information Technology & CIO	Jeff Glenn	210,000
31			
32	Vice President of Regulatory Affairs	Tim Tatum	170,000
33			
34	(1)Retirement effective 06/30/16. Salary shows YTD wages		
35	(2)Retirement effective 12/31/16. Salary shows YTD wages		
36	(3)Retirement effective 03/31/16. Salary shows YTD wages		
37	(4)Retirement effective 04/30/16. Salary shows YTD wages		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1		
2	Judith A. Johansen	10446 E. Palo Brea Dr., Scottsdale, Arizona 85262
3		
4	Christine King***	8527 East Old Field Rd
5		Scottsdale, Arizona 85266
6		
7	Thomas Carlile	2719 North Woodview place, Boise Idaho 83702
8		
9	Darrel T. Anderson President & CEO, ** ***	Idaho Power Company, 1221 W. Idaho Street,
10		P.O. Box 70, Boise, Idaho 83707-0070
11		
12	J. LaMont Keen	481 North Strata Via Way, Boise Idaho 83712
13		
14	Robert A. Tinstman ***	4433 W. Quail Point Court, Boise, Idaho 83703
15		
16	Richard Dahl ***	60 Laiki Pl.
17		Kailua, Hawaill 96734
18		
19	Dennis L. Johnson	United Heritage Life Insurance
20		926 W Oakhampton Dr, Eagle, Idaho 83616
21		
22	Ronald W. Jibson	Questar Corporation
23		417 Aerie Circle, North Salt Lake City, Utah 84054
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25	Richard J. Navarro	1256 E. Candleridge Ct., Boise, Idaho 83712
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

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

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff	
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	201608295362	08/29/2016	ER-09-1641-000	Idaho Power Company	FERC Electric Tariff
2				2016 Annual	
3				Informational Filling	
4				under ER-09-1641-000	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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).	Schedule	Column	Line No
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 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.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. None

2. None

3. To enhance the abilities of Idaho Power and PacifiCorp to serve their respective customers, on October 24, 2014, Idaho Power and PacifiCorp executed a Joint Ownership and Operating Agreement (Joint Operating Agreement) applicable to certain transmission-related equipment to be exchanged by Idaho Power and PacifiCorp. The exchange was made pursuant to the terms of a Joint Purchase and Sale Agreement, also dated October 24, 2014, between Idaho Power and PacifiCorp, under which each party agreed to transfer to the other specified transmission-related equipment with a net book value of approximately $45 million as of the closing date. The transaction also provided for the termination and amendment of a number of legacy long-term agreements related to the ownership and operation of jointly-owned facilities and transmission services between Idaho Power and PacifiCorp. Idaho Power received FERC approval of the transaction on June 17, 2015 (*See: Idaho Power Co., PacifiCorp*, 151 FERC ¶ 61,233 (2015). FERC Docket No. EC15-54-000*).* As a condition of approval, FERC required Idaho Power and PacifiCorp to submit final accounting for the transaction within six months of the transaction’s closing. (See: *Idaho Power Co., PacifiCorp*, Order Authorizing Acquisition and Disposition of Jurisdictional Facilities, 151 FERC ¶ 61,233 (2015). The transaction closed on October 30, 2015 and final accounting was submitted to FERC on April 27, 2016.

4. None

5. None

6. In December 2016, Idaho Power borrowed $21,800,000 in commercial paper, which was repaid in January 2017. In April and May 2016, Idaho Power received orders from the IPUC, OPUC, and WPSC authorizing Idaho Power to issue and sell from time to time up to $500 million 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 May 31, 2019, subject to extension upon request to the IPUC. The OPUC's and WPSC's orders do not impose a time limitation for issuances.

On March 10, 2016, Idaho Power issued $120 million in principal amount of 4.05% first mortgage bonds, secured medium-term notes, Series J, maturing on March 1, 2046. In April 2013, Idaho Power received orders from the IPUC, OPUC, and WPSC authorizing Idaho Power to issue and sell from time to time up to $500 million in aggregate principal amount of debt securities and first mortgage bonds, subject to conditions specified in the orders. Authority from the IPUC was through April 9, 2015. On April 1, 2015, the IPUC approved a two-year extension through April 9, 2017, continuing Idaho Power's authorization to issue and sell from time to time debt securities and first mortgage bonds.

7. None

8. Effective 12/31/2016 a 2.75% general wage adjustment was implemented.

9. Disclosed in Financial Statement footnotes, see pages 123.22 to 123.23

10. All of the below related person transactions were reviewed and approved by the Idaho Power Board of Directors and the Corporate Governance and Nominating Committee.

- Steven R. Keen, Idaho Power's Senior Vice President, Chief Financial Officer and Treasurer is the brother of J. LaMont Keen, a member of Idaho Power's board of directors.
- Rex Blackburn is the Sr. Vice President and General Counsel of Idaho power. His brother-in-law, Gary Betts, is also an employee of Idaho Power.
- Patrick A. Harrington is the Corporate Secretary of Idaho Power. His brother, Jamie Harrington, is also an employee of Idaho Power.

- Lori D. Smith was the Vice President and Chief Risk Officer of Idaho Power. Her husband, Matt Smith, was also an employee of Idaho Power.
- Jeff Glenn is the the Vice President of Information Technology & CIO of Idaho Power. His wife, Jill Glenn, is also an employee of Idaho Power.
- Dan Minor was the Executive Vice President of Idaho Power. His sister, Deb Mann, is also an employee of Idaho Power.

11. None

12. None

13. Officer Changes in 2016:
    - Daniel B. Minor retired as Executive Vice President and Chief Operating Officer effective 6/30/2016
    - Gregory W. Said retired as Vice President- Regulatory Affairs effective 4/30/2016
    - Lori D. Smith retired as Vice President, Chief Risk Officer effective 3/31/2016
    - Brian R. Buckham was appointed Vice President and General Counsel effective 4/1/2016
    - Tim E. Tatum was appointed Vice President- Regulatory Affairs effective 3/1/2016
    - Tess R. Park was appointed Vice President of Power Supply effective 1/1/2016
    - Jeff S. Glenn was appointed Vice President of Information Technology effective 1/23/2016
    - Jeff S. Glenn's title changed to Vice President of Information Technology and Chief Information Officer effective 5/23/2016
    - Rex Blackburn's title changed from "Sr. Vice President and General Counsel" to "Sr. Vice President" effective 4/1/2016
    - Lisa A. Grow's title changed from "Sr. Vice President- Power Supply" to "Sr. Vice President of Operations" effective 1/1/2016
    - Lonnie G. Krawl's title changed from "Vice President of Human Resources, Administrative Services & Chief Information Officer" to "Sr. Vice President of Administrative Services and Chief Information Officer" effective 1/1/2016
    - Lonnie G. Krawl's title changed from "Sr. Vice President of Administrative Services and Chief Information Officer" to "Sr. Vice President of Administrative Services and Chief Human Resources Officer" effective 5/23/16
    - Jeffrey L. Malmen's title changed from "Vice President- Public Affairs" to "Sr. Vice President- Public Affairs" effective 4/1/2016
    - N. Vern Porter's title changed from "Sr. Vice President of Customer Operations" to "Vice President of Customer Operations" effective 1/1/2016

14. Idaho Power and its unregulated parent, IDACORP have separate cash management programs (separate bank accounts, liquidity facilities, short-term debt and investment programs). No money has been loaned or advanced from Idaho Power to IDACORP through a cash management program.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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)	200-201	5,739,484,446	5,492,554,138
3	Construction Work in Progress (107)	200-201	405,068,524	396,931,372
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		6,144,552,970	5,889,485,510
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,175,085,495	2,097,432,010
6	Net Utility Plant (Enter Total of line 4 less 5)		3,969,467,475	3,792,053,500
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		3,969,467,475	3,792,053,500
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		1,071,638	1,555,480
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	77,130,927	84,137,401
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		0	416
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		24,018,570	24,560,677
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	126,480
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		102,221,135	110,380,454
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		14,159,468	100,745,383
36	Special Deposits (132-134)		1,168,084	1,637,072
37	Working Fund (135)		13,600	10,600
38	Temporary Cash Investments (136)		29,967,367	10,000,000
39	Notes Receivable (141)		-83,038	0
40	Customer Accounts Receivable (142)		73,276,818	75,650,719
41	Other Accounts Receivable (143)		25,535,458	23,486,155
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,131,759	1,355,042
43	Notes Receivable from Associated Companies (145)		0	1,156,202
44	Accounts Receivable from Assoc. Companies (146)		0	0
45	Fuel Stock (151)	227	53,700,442	61,818,257
46	Fuel Stock Expenses Undistributed (152)	227	-2,623	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	54,454,684	52,445,228
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

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)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	3,403,797	4,478,320
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		18,269,814	17,845,551
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		24,539	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		80,738,420	65,804,608
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		5,951,233	405,239
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	126,480
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		359,446,304	414,001,812
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		16,313,567	16,539,636
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	1,471,940,401	1,355,572,128
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	1,177
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		1,290,608	1,650,910
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	75,332,657	66,701,295
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		41,975,568	29,731,072
82	Accumulated Deferred Income Taxes (190)	234	286,326,529	270,188,395
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,893,179,330	1,740,384,613
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,324,314,244	6,056,820,379

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	end of 2016/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)	250-251	97,877,030	97,877,030
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		712,257,435	712,257,435
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	2,096,925	2,096,925
11	Retained Earnings (215, 215.1, 216)	118-119	1,136,879,473	1,045,751,377
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	74,667,833	81,674,308
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-20,881,620	-21,275,735
16	Total Proprietary Capital (lines 2 through 15)		1,998,703,226	1,914,187,490
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,745,460,000	1,725,460,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	20,948,636	22,012,273
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		4,417,463	4,458,587
24	Total Long-Term Debt (lines 18 through 23)		1,761,991,173	1,743,013,686
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		1,792,128	1,873,877
29	Accumulated Provision for Pensions and Benefits (228.3)		411,633,628	394,131,877
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		103,219,162	87,689,554
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		26,257,286	26,152,620
35	Total Other Noncurrent Liabilities (lines 26 through 34)		542,902,204	509,847,928
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		21,800,000	0
38	Accounts Payable (232)		126,470,087	119,524,930
39	Notes Payable to Associated Companies (233)		244,435	0
40	Accounts Payable to Associated Companies (234)		1,056,374	1,058,872
41	Customer Deposits (235)		2,864,762	4,731,724
42	Taxes Accrued (236)	262-263	-11,945,257	5,192,418
43	Interest Accrued (237)		22,539,658	22,387,590
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

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)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		2,847,908	1,921,386
48	Miscellaneous Current and Accrued Liabilities (242)		49,816,656	53,364,600
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	4,972,600
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		215,694,623	213,154,120
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		5,252,737	4,678,929
57	Accumulated Deferred Investment Tax Credits (255)	266-267	79,959,845	79,654,930
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	10,479,342	11,757,998
60	Other Regulatory Liabilities (254)	278	77,043,013	67,711,655
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		1,449,526,847	1,349,907,020
64	Accum. Deferred Income Taxes-Other (283)		182,761,234	162,906,623
65	Total Deferred Credits (lines 56 through 64)		1,805,023,018	1,676,617,155
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,324,314,244	6,056,820,379

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin 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.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

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)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,255,298,799	1,266,201,447		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	734,428,076	731,125,349		
5	Maintenance Expenses (402)	320-323	67,074,765	69,399,154		
6	Depreciation Expense (403)	336-337	135,048,584	130,382,128		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	720,272	549,017		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	6,649,455	7,095,926		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		1,242,422	82,611		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	32,823,311	32,808,301		
15	Income Taxes - Federal (409.1)	262-263	-96,137	12,593,365		
16	- Other (409.1)	262-263	3,659,280	5,986,110		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	58,087,034	86,269,807		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	26,177,294	58,085,989		
19	Investment Tax Credit Adj. - Net (411.4)	266	304,915	492,099		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		49,266	97,422		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		231,983	232,049		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,013,947,400	1,018,832,505		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		241,351,399	247,368,942		

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders 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.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,255,298,799	1,266,201,447					2
						3
734,428,076	731,125,349					4
67,074,765	69,399,154					5
135,048,584	130,382,128					6
720,272	549,017					7
6,649,455	7,095,926					8
						9
						10
						11
1,242,422	82,611					12
						13
32,823,311	32,808,301					14
-96,137	12,593,365					15
3,659,280	5,986,110					16
58,087,034	86,269,807					17
26,177,294	58,085,989					18
304,915	492,099					19
						20
						21
49,266	97,422					22
						23
231,983	232,049					24
1,013,947,400	1,018,832,505					25
241,351,399	247,368,942					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		241,351,399	247,368,942		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		4,054,219	1,304,085		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		3,886,708	1,485,862		
33	Revenues From Nonutility Operations (417)		31,177	33,733		
34	(Less) Expenses of Nonutility Operations (417.1)		97,371	10,586		
35	Nonoperating Rental Income (418)		-4,136	-791		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	7,993,526	6,659,942		
37	Interest and Dividend Income (419)		4,241,119	3,039,556		
38	Allowance for Other Funds Used During Construction (419.1)		22,030,622	21,785,246		
39	Miscellaneous Nonoperating Income (421)		3,064,489	2,365,842		
40	Gain on Disposition of Property (421.1)		7,631	-20		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		37,434,568	33,691,145		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		986,820	750,960		
46	Life Insurance (426.2)		-2,588,290	-1,738,804		
47	Penalties (426.3)		-3	48,305		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,549,848	1,477,633		
49	Other Deductions (426.5)		9,203,000	9,937,000		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		9,151,375	10,475,094		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	28,463	21,055		
53	Income Taxes-Federal (409.2)	262-263	560,490	353,061		
54	Income Taxes-Other (409.2)	262-263	107,192	69,362		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	164,060	5,911,613		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	2,307,095	8,478,300		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-1,446,890	-2,123,209		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		29,730,083	25,339,260		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		81,956,468	83,055,805		
63	Amort. of Debt Disc. and Expense (428)		1,515,157	1,556,825		
64	Amortization of Loss on Reaquired Debt (428.1)		2,033,523	1,521,812		
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)		27,622	6,859		
68	Other Interest Expense (431)		6,500,414	5,627,193		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		10,193,622	10,043,775		
70	Net Interest Charges (Total of lines 62 thru 69)		81,839,562	81,724,719		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		189,241,920	190,983,483		
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)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		189,241,920	190,983,483		

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STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, 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 of 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 in 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, include them on pages 122-123.

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		1,032,478,271	939,062,769
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		181,248,394	184,323,541
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-105,120,298	(96,908,039)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-105,120,298	(96,908,039)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		15,000,000	6,000,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,123,606,367	1,032,478,271
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, 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 of 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 in 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, include them on pages 122-123.

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)
41				
42				
43				
44				
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)		13,273,106	13,273,106
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		13,273,106	13,273,106
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,136,879,473	1,045,751,377
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		81,674,308	81,014,366
50	Equity in Earnings for Year (Credit) (Account 418.1)		7,993,526	6,659,942
51	(Less) Dividends Received (Debit)		15,000,000	6,000,000
52				
53	Balance-End of Year (Total lines 49 thru 52)		74,667,834	81,674,308

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction 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)	189,241,920	190,983,483
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	135,048,584	130,382,128
5	Amortization of	11,644,970	11,590,185
6			
7			
8	Deferred Income Taxes (Net)	29,875,896	25,793,350
9	Investment Tax Credit Adjustment (Net)	195,726	315,879
10	Net (Increase) Decrease in Receivables	3,368,760	3,988,719
11	Net (Increase) Decrease in Inventory	7,244,713	-8,079,325
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-3,831,716	17,501,301
14	Net (Increase) Decrease in Other Regulatory Assets	-18,744,516	1,465,215
15	Net Increase (Decrease) in Other Regulatory Liabilities	13,093,929	12,233,990
16	(Less) Allowance for Other Funds Used During Construction	22,030,622	21,785,246
17	(Less) Undistributed Earnings from Subsidiary Companies	-7,006,474	659,942
18	Other (provide details in footnote):	-42,248,053	-18,199,440
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	309,866,065	345,530,297
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-318,978,793	-315,753,782
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	-22,030,622	-21,785,246
31	Other (provide details in footnote):	8,558,677	13,456,680
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-288,389,494	-280,511,856
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	83,038	896,996
40	Contributions and Advances from Assoc. and Subsidiary Companies	1,400,637	
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-24,916,896	-44,105,638
45	Proceeds from Sales of Investment Securities (a)	15,693,370	34,243,180

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):	-55,676	-1,374,426
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-296,185,021	-290,851,744
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	120,000,000	250,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	120,000,000	250,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-101,063,636	-121,063,637
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-15,912,658	-22,646,072
77			
78	Net Decrease in Short-Term Debt (c)	21,800,000	
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-105,120,298	-96,908,039
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-80,296,592	9,382,252
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-66,615,548	64,060,805
87			
88	Cash and Cash Equivalents at Beginning of Period	110,755,983	46,695,178
89			
90	Cash and Cash Equivalents at End of period	44,140,435	110,755,983

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Schedule Page: 120 Line No.: 5 Column: b

Amortization

Plant	6,649,455
Unamortized debt expense	3,576,062
Unamortized discount	295,752
Water rights	1,042,009
Other	81,692
	11,644,970

Schedule Page: 120 Line No.: 13 Column: b

Cash (received) paid during the period for:

Income taxes	22,005,067
Interest (net of amount capitalized)	78,111,192

Schedule Page: 120 Line No.: 18 Column: b

Cash Flow from Operating Activities (Other)

Pension and postretirement benefit plan expense	29,596,861
Contributions to pension and postretirement benefit plans	(45,316,746)
Unbilled revenues	(15,670,298)
Accrued payroll	(4,883,134)
Prepayments	(2,476,233)
Company owned life insurance	1,013,075
Deposits from third parties	(1,504,654)
Other	(3,006,925)
	(42,248,053)

Schedule Page: 120 Line No.: 26 Column: b

Non-cash investing activities:

Additions to PP&E in accounts payable	34,602,938

Schedule Page: 120 Line No.: 31 Column: b

Other Cash Flows from Plant

Payments received from joint funding partners	7,586,142
Sale of emission allowances and renewable energy certificates	971,165
Other	1,371
	8,558,677

Schedule Page: 120 Line No.: 53 Column: b

Other Investing Cash Flows

Feasibility study costs	(65,296)
Miscellaneous other investing activities	9,620
	(55,676)

Schedule Page: 120 Line No.: 76 Column: b

Other Financing Cash Flows

Make-whole premium on retirement of long-term debt	(13,895,000)
Debt issuance costs	(1,708,058)
Discount on debt issuance	(309,600)
	(15,912,658)

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)
1	Balance of Account 219 at Beginning of Preceding Year				(24,157,999)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				2,667,521
3	Preceding Quarter/Year to Date Changes in Fair Value				214,743
4	Total (lines 2 and 3)				2,882,264
5	Balance of Account 219 at End of Preceding Quarter/Year				(21,275,735)
6	Balance of Account 219 at Beginning of Current Year				(21,275,735)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				2,253,040
8	Current Quarter/Year to Date Changes in Fair Value				(1,858,925)
9	Total (lines 7 and 8)				394,115
10	Balance of Account 219 at End of Current Quarter/Year				(20,881,620)

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(24,157,999)		
2			2,667,521		
3			214,743		
4			2,882,264	190,983,483	193,865,747
5			(21,275,735)		
6			(21,275,735)		
7			2,253,040		
8			(1,858,925)		
9			394,115	189,241,920	189,636,035
10			(20,881,620)		

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

IDAHO POWER COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Idaho Power Company (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, sales, and purchase of electric energy and capacity with a service area covering approximately 24,000 square miles in southern Idaho and eastern Oregon. 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 venturer in Bridger Coal Company (BCC), which mines and supplies coal to the Jim Bridger generating plant owned in part by Idaho Power.

Basis of Reporting

The financial statements include the assets, liabilities, revenues and expenses of Idaho Power and 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 these financial statements. These estimates and assumptions include those related to rate regulation, retirement benefits, contingencies, litigation, asset impairment, income taxes, unbilled revenues, and bad debt. 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.

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.

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’s financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating

Idaho Power. 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 enterprise 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 and recorded on the income statement when recovered or returned in rates. Additionally, regulators can impose regulatory liabilities upon a regulated company for amounts previously collected from customers that are expected to be refunded. The effects of applying these regulatory accounting principles to Idaho Power's operations are discussed in more detail in Note 3.

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 may be assessed on account balances after 30 days. An allowance is recorded for potential uncollectible accounts. The allowance is reviewed periodically and adjusted based upon a combination of historical write-off experience, aging of accounts receivable, and an analysis of specific customer accounts. Adjustments are charged to income. Customer accounts receivable balances that remain outstanding after reasonable collection efforts are written off.

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, 2016 and 2015. 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 changes in fair value of derivative instruments related to power supply as regulatory assets or liabilities.

Revenues

Operating revenues related to Idaho Power's sale of energy are recorded when service is rendered or energy is delivered to customers. Idaho Power accrues estimated unbilled revenues for electric services delivered to customers but not yet billed at year-end. In addition, regulatory mechanisms in place in Idaho and Oregon affect the reported amount of revenue. See Note 3 for additional discussion of certain of the following mechanisms:

- energy efficiency riders to fund energy efficiency program expenditures. Expenditures funded through the riders are reported as an operating expense with an equal amount of revenues recorded in other revenues;
- a fixed cost adjustment mechanism that results in recording additional or reduced revenue based on the allowed and actual fixed costs recovered through current rates;
- a sharing mechanism providing for refunds to customers for earnings above stated returns on equity in Idaho;
- franchise fees and similar taxes related to energy consumption. None of these collections are reported on the income statement; and
- collection in base rates of a portion of the allowance for funds used during construction (AFUDC) related to its Hells Canyon Complex (HCC) relicensing project. Cash collected under this ratemaking mechanism is not recorded as revenue but is instead deferred as a regulatory liability.

Property, Plant and Equipment and Depreciation

The cost of utility plant in service represents the original cost of contracted services, direct labor and material, 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 2.64 percent in 2016 and 2.68 percent in 2015.

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 consolidated balance sheets. If the project becomes probable of being abandoned, such costs are expensed in the period such determination is made. Idaho Power may seek recovery of such 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 2016 or 2015.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, as discussed above 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. The component of AFUDC attributable to borrowed funds is included as a reduction to total interest expense. Idaho Power's weighted-average monthly AFUDC rate was 7.6 percent for both 2016 and 2015.

Income Taxes

Idaho Power accounts 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 provide deferred income taxes 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. Regulated enterprises are required to recognize 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.

In compliance with the federal income tax requirements for the use of accelerated tax depreciation, Idaho Power provides 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 provided for other temporary differences unless accounted for using flow-through.

The state of Idaho allows a three percent investment tax credit on qualifying plant additions. Investment tax credits earned on regulated assets are deferred and amortized to income over the estimated service lives of the related properties. Credits earned on non-regulated assets or investments are recognized in the year earned.

Income taxes are discussed in more detail in Note 2.

Other Accounting Policies

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

Supplemental Cash Flows Information

In 2015, Idaho Power executed an agreement to exchange property with another electric utility. Under the terms of the agreement, each party transferred to the other transmission-related equipment with a book value of approximately $44 million. Idaho Power received an immaterial amount of cash, representing the difference in the book value of the assets exchanged. Also in 2015, Idaho Power executed a long-term service agreement and transferred to the service provider approximately $22 million of spare parts in partial exchange for future services. No cash was exchanged in the 2015 transfer transaction.

Reclassifications

In these consolidated financial statements, certain immaterial amounts in prior periods' consolidated financial statements and footnotes have been reclassified to conform with the current period presentation.

New and Recently Adopted Accounting Pronouncements

Recently Adopted Accounting Pronouncements

In March 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2016-09, *Compensation--Stock Compensation (Topic 718) - Improvements to Employer Share-Based Payment Accounting,* simplifying several aspects of the accounting for stock compensation paid to employees. As allowed, Idaho Power elected to early adopt the provisions of the new standard in the first quarter of 2016 under the modified retrospective method.

In May 2015, the FASB issued ASU 2015-07, *Fair Value Measurement (Topic 820) - Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent),* which removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. As required, Idaho Power has adopted the provisions of this ASU at December 31, 2016, and accordingly, has retrospectively adjusted prior periods.

In February 2015, the FASB issued ASU 2015-02, C*onsolidation (Topic 810) - Amendments to the Consolidation Analysis,* which revises the consolidation model that reporting entities use when determining what entities are to be consolidated. The amendments focus on limited partnerships and similar legal entities. The adoption of ASU 2015-02 in the first quarter of 2016 did not have a material impact on Idaho Power's financial statements.

Recent Accounting Pronouncements Not Yet Adopted

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. ASU 2014-09 is intended to enable users of financial statements to better understand and consistently analyze an entity's revenue across industries, transactions, and geographies. Under the ASU, recognition of revenue occurs when a customer obtains control of promised goods or services. In addition, the ASU requires disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The FASB amended certain aspects of ASU 2014-09 to clarify the implementation guidance, including clarifications related to principal versus agent considerations, licensing and identifying performance obligations, narrow scope improvements, and practical expedients. Idaho Power continues to assess the impacts of ASU 2014-09 on their financial statements, including disclosure requirements, but does not expect the new guidance to significantly affect revenue recognition for tariff-based sales, which represent a significant majority of Idaho Power's general business revenue. Accordingly, Idaho Power does not expect the adoption of ASU 2014-09 to have a material effect on its financial statements; however, a number of industry-specific implementation issues are still unresolved and the final resolution of these issues could affect the Idaho Power's accounting for contributions in aid of construction, sales of renewable energy credits, alternative revenue programs, and recognition of revenue when collectability is in question. The guidance in ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2017, including interim periods. The guidance permits two implementation approaches, one requiring retrospective application of the new standard with restatement of prior years (full retrospective approach) and one requiring prospective application of the new standard including a cumulative-effect adjustment with disclosure of results under previous standards (modified-retrospective approach). Idaho Power plans to adopt ASU 2014-09 on January 1, 2018, using the modified-retrospective approach.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, intended to improve financial reporting about leasing transactions. The ASU significantly changes the accounting model used by lessees to account for leases, requiring that all material leases be presented on the balance sheet. Under the current model, some leases are classified as capital leases and recorded on the balance sheet while other leases classified as operating leases are not recognized on the balance sheet. The new standard is effective for annual reporting periods beginning after December 15, 2018, including interim periods, with early adoption permitted. The standard must be adopted using a modified-retrospective approach. Idaho Power is evaluating the impact of ASU 2016-02 on its financial statements. At this time, Idaho Power does not know, and cannot reasonably estimate, the dollar impact of the adoption. Specifically, Idaho Power is considering whether the new guidance will affect its accounting for purchase power agreements, easements and rights-of-way, utility pole attachments, and other utility industry-related areas.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230)*, which amends ASC 230 to clarify guidance on the classification of certain cash receipts and payments in the statement of cash flows. The FASB issued the ASU with the intent of reducing diversity in practice with respect to eight types of cash flows. Idaho Power expects the ASU to affect the classification of proceeds from the settlement of corporate-owned life insurance policies and related costs, which will be classified as investing activities under the new guidance. Idaho Power already presents debt prepayment and extinguishment costs, proceeds from the settlement of insurance claims (other than corporate-owned life insurance), and distributions received from equity-method investments in accordance with the new guidance. ASU 2016-15 is effective for annual reporting periods beginning after December 15, 2017, including interim periods, with early adoption permitted one year earlier. Idaho Power does not plan to early adopt the standard. The standard must be adopted retrospectively to all periods presented, unless impracticable to do so. Idaho Power does not believe the adoption will have a material impact on their financial statements.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2016, up to February 23, 2017, the date that Idaho Power Company’s U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 14, 2017. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

2. INCOME TAXES

A reconciliation between the statutory federal income tax rate and the effective tax rate is as follows:

	2016	2015
	(thousands of dollars)	
Federal income tax expense at 35% statutory rate	$ 78,241	$ 82,633
Change in taxes resulting from:		
Equity earnings of subsidiary companies	(2,798)	(2,331)
AFUDC	(11,278)	(11,140)
Capitalized interest	2,000	2,693
Investment tax credits	(2,922)	(2,963)
Bond redemption costs	(4,997)	(6,459)
Removal costs	(5,559)	(4,807)
Capitalized overhead costs	(10,500)	(8,750)
Capitalized repair costs	(28,000)	(28,700)
Tax method change – capitalized repairs	—	—
State income taxes, net of federal benefit	4,880	7,503
Depreciation	18,673	17,149
Share-based compensation	(1,583)	—
Other, net	(1,855)	283
Total income tax expense	$ 34,302	$ 45,111
Effective tax rate	15.30%	19.10%

The items comprising income tax expense are as follows:

	2016	2015
	(thousands of dollars)	
Income taxes currently payable:		
Federal	$ 464	$ (12,946)
State	3,767	6,056
Total	4,231	19,002
Income taxes deferred:		
Federal	31,798	28,103
State	(2,032)	(2,486)
Total	29,766	25,617
Investment tax credits:		
Deferred	3,227	3,455
Restored	(2,922)	(2,963)
Total	305	492
Total income tax expense	34,302	45,111

The components of the net deferred tax liability are as follows:

	2016	2015
	(thousands of dollars)	
Deferred tax assets:		
Regulatory liabilities	$ 51,326	$ 51,131
Deferred compensation	29,424	27,489
Deferred revenue	40,354	34,282
Tax credits	33,488	30,223
Retirement benefits	132,362	126,885
Other	11,069	10,745
Total	298,023	280,755
Deferred tax liabilities:		
Property, plant and equipment	500,987	474,879
Regulatory assets	948,540	875,028
Power cost adjustment	21,077	18,489
Fixed cost adjustment	17,376	14,395
Retirement benefits	140,083	126,090
Other	15,922	14,499
Total	1,643,985	1,523,380
Net deferred tax liabilities	$ 1,345,962	$ 1,242,625

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. See Note 1 for further discussion of accounting policies related to income taxes.

Uncertain Tax Positions

Idaho Power believes that it has no material income tax uncertainties for 2016 and prior tax years. The Company 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 - U.S. federal and the State of Idaho. The open tax years for examination are 2016 for federal and 2012-2016 for Idaho. In May 2009, IDACORP formally entered the U.S. Internal Revenue Service (IRS) Compliance Assurance Process (CAP) program for its 2009 tax year and has remained in the CAP program for all subsequent years. The CAP program provides for IRS examination and issue resolution throughout the current year with the objective of return filings containing no contested items. In 2016, the IRS completed its examination of IDACORP's 2015 tax year with no unresolved income tax issues.

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.

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 such 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):

	As of December 31, 2016				
Description	Remaining Amortization Period	Earning a Return(1)	Not Earning a Return	Total as of 2016	December 31, 2015
Regulatory Assets:					
Income taxes		$ —	$ 948,540	$ 948,540	$ 875,027
Unfunded postretirement benefits(2)		—	263,779	263,779	251,762
Pension expense deferrals		83,057	22,295	105,352	85,790
Energy efficiency program costs(3)		5,552	—	5,552	4,482
Power supply costs(4)	2017-2018	53,911	—	53,911	47,220
Fixed cost adjustment(4)	2017-2018	44,445	—	44,445	36,820
Asset retirement obligations(5)		—	14,154	14,154	14,410
Mark-to-market liabilities(6)		—	—	—	4,973
Long-term service agreement(7)	2043	17,879	11,202	29,081	30,225
Other	2017-2054	2,541	4,585	7,126	4,800
Total		$ 207,385	$ 1,264,555	$ 1,471,940	$ 1,355,509
Regulatory Liabilities:					
Income taxes		$ —	$ 51,326	$ 51,326	$ 51,131
Energy efficiency program costs(3)		10,730	—	10,730	6,554
Settlement agreement sharing mechanism(4)		—	—	—	3,159
Mark-to-market assets(6)		—	7,831	7,831	405
Other		5,639	1,516	7,155	6,399
Total		$ 16,369	$ 60,673	$ 77,042	$ 67,648

(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.

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

(3) The energy efficiency asset represents the Oregon jurisdiction balance and the liability represents the Idaho jurisdiction balance.

(4) These items are discussed in more detail in this Note 3.

(5) Asset retirement obligations are discussed in Note 13.

(6) Mark-to-market assets and liabilities are discussed in Note 16.

(7) A portion not earning a return as of December 31, 2016, will be eligible to earn a return as of January 1, 2018.

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 off-system 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 credit on the balance sheets for future recovery or refund. The power supply costs deferred primarily result from changes in contracted power purchase prices and volumes, changes in wholesale market prices and transaction volumes, fuel prices, and the levels of Idaho Power's own generation. The Idaho deferral period or PCA year runs from April 1 through March 31. Amounts deferred during the PCA year are primarily recovered or refunded during the subsequent June 1 through May 31 period.

Idaho Jurisdiction Power Cost Adjustment Mechanism: In the Idaho jurisdiction, the annual PCA adjustment 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 true-up component, based on the difference between the previous year's actual net power supply costs and the previous year's forecast. The latter component also includes a balancing mechanism so that, over time, the actual collection or refund of authorized true-up dollars matches the amounts authorized. The PCA mechanism also includes:

- a cost or benefit sharing ratio that allocates the deviations in net power supply expenses between customers (95 percent) and shareholders (5 percent), with the exceptions of expenses associated with PURPA power purchases 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 changes does not distort the results of the mechanism.

The table below summarizes the three most recent PCA rate adjustments, all of which also include non-PCA-related rate adjustments as ordered by the IPUC:

Effective Date	$ Change (millions)	Notes
June 1, 2016	$ 17.3	The net increase in PCA rates included the application of (a) a customer rate credit of $3.2 million for sharing of revenues with customers for the year 2015 under the terms of the October 2014 settlement stipulation, and (b) $4.0 million reduction due to the transfer of Idaho energy efficiency rider funds.
June 1, 2015	$ (11.6)	The net decrease in PCA rates included the application of (a) a customer rate credit of $8.0 million for sharing of revenues with customers for the year 2014 under the terms of the December 2011 settlement stipulation, and (b) $4.0 million of surplus Idaho energy efficiency rider funds.

In July 2014, the IPUC opened a docket pursuant to which Idaho Power, the IPUC Staff, and other interested parties further evaluated Idaho Power's application of the true-up component of the PCA mechanism and whether a deferral balance adjustment was appropriate. While the IPUC's docket was closed in August 2014 with no adjustment to the PCA true-up revenue amount, Idaho Power subsequently met with the IPUC Staff to explore approaches to increasing the accuracy of the actual cost recovery under the PCA mechanism. In May 2015, the IPUC approved a settlement stipulation that resulted in the replacement of the existing load-based adjustment used for determining the power cost deferrals under the PCA mechanism with a similar sales-based adjustment. The sales-based adjustment functions in the same manner as the previous load-based adjustment but measures deviations between Idaho-specific test year sales and actual Idaho sales rather than deviations between test year loads and actual loads. The approved settlement stipulation implemented the new methodology as of January 1, 2015.

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 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. Under the PCAM, Idaho Power is subject to a portion of the business risk or benefit associated with this deviation through application of an asymmetrical deadband (or range of deviations) within which Idaho Power absorbs cost increases or decreases. For deviations in actual power supply costs outside of the deadband, the PCAM provides for 90/10 sharing of costs and benefits between customers and Idaho Power. However, collection by Idaho Power will occur only to the extent that Idaho Power's actual Oregon-jurisdictional return on equity (Oregon ROE) for the year is no greater than 100 basis points below Idaho Power's last authorized Oregon ROE. A refund to customers will occur only to the extent that Idaho Power's actual Oregon ROE for that year is no less than 100 basis points above Idaho Power's last authorized Oregon ROE. Oregon jurisdiction power supply cost changes under the APCU and PCAM during each of 2016 and 2015 are summarized in the table that follows:

Year and Mechanism	APCU or PCAM Adjustment
2016 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2016 APCU	A rate increase of $0.2 million annually took effect June 1, 2016.
2015 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2015 APCU	A rate decrease of $0.7 million annually took effect June 1, 2015.

Notable Idaho Regulatory Matters

Idaho Base Rate Changes: Idaho base rates were most recently established in 2012, and adjusted in 2014. Effective January 1, 2012, Idaho Power implemented new Idaho base rates resulting from IPUC approval of a settlement stipulation that provided for a 7.86 percent authorized overall rate of return on an Idaho-jurisdiction rate base of approximately $2.36 billion. The settlement stipulation resulted in a 4.07 percent, or $34.0 million, overall increase in Idaho Power's annual Idaho-jurisdiction base rate revenues. Idaho base rates were subsequently adjusted again in 2012, in connection with Idaho Power's completion of the Langley Gulch power plant. In June 2012, the IPUC issued an order approving a $58.1 million increase in annual Idaho-jurisdiction base rates, effective July 1, 2012. The order also provided for a $335.9 million increase in Idaho rate base. Neither the settlement stipulation nor the IPUC orders adjusting base rates specified an authorized rate of return on equity or imposed a moratorium on Idaho Power filing a general rate case at a future date.

As noted above in this Note 3, the IPUC also issued a March 2014 order approving Idaho Power's request for an increase in the normalized or "base level" net power supply expense to be used to update base rates and in the determination of the PCA rate that became effective June 1, 2014.

December 2011 Idaho Settlement Stipulation: In December 2011, the IPUC issued an order, separate from the then-pending general rate case proceeding, approving a settlement stipulation that provided as follows:

- If Idaho Power's actual Idaho-jurisdiction return on year-end equity (Idaho ROE) for 2012, 2013, or 2014 was less than 9.5 percent, then Idaho Power could amortize up to a total of $45 million of additional accumulated deferred investment tax credits (ADITC) to help achieve a minimum 9.5 percent Idaho ROE in the applicable year.
- If Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeded 10.0 percent, the amount of Idaho Power's Idaho-jurisdiction earnings exceeding a 10.0 percent and up to and including a 10.5 percent Idaho ROE for the applicable year would be shared equally between Idaho Power and its Idaho customers in the form of a rate reduction to become effective at the time of the subsequent year's PCA mechanism adjustment.
- If Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeded 10.5 percent, the amount of Idaho Power's Idaho jurisdictional earnings exceeding a 10.5 percent Idaho ROE for the applicable year would be allocated 75 percent to Idaho Power's Idaho customers as a reduction to the pension regulatory asset and 25 percent to Idaho Power.

October 2014 Idaho Settlement Stipulation: In October 2014, the IPUC issued an order approving an extension, with modifications, of the terms of the December 2011 Idaho settlement stipulation for the period from 2015 through 2019, or until the terms are otherwise modified or terminated by order of the IPUC or the full $45 million of additional ADITC contemplated by the settlement stipulation has been amortized. The provisions of the new settlement stipulation are as follows:

- If Idaho Power's annual Idaho ROE in any year is less than 9.5 percent, then Idaho Power may amortize up to $25 million of additional ADITC to help achieve a 9.5 percent Idaho ROE for that year, and may amortize up to a total of $45 million of additional ADITC over the 2015 through 2019 period.
- If Idaho Power's annual Idaho ROE in any year exceeds 10.0 percent, the amount of earnings exceeding a 10.0 percent Idaho ROE and up to and including a 10.5 percent Idaho ROE will be allocated 75 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's PCA and 25 percent to Idaho Power.
- If Idaho Power's annual Idaho ROE in any year exceeds 10.5 percent, the amount of earnings exceeding a 10.5 percent Idaho ROE will be allocated 50 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's PCA, 25 percent to Idaho Power's Idaho customers in the form of a reduction to the pension expense deferral regulatory asset (to reduce the amount to be collected in the future from Idaho customers), and 25 percent to Idaho Power.
- If the full $45 million of additional ADITC contemplated by the settlement stipulation has been amortized the sharing provisions would terminate.
- In the event the IPUC approves a change to Idaho Power's Idaho-jurisdictional allowed return on equity as part of a general rate case proceeding seeking a rate change effective prior to January 1, 2020, the Idaho ROE thresholds (9.5 percent, 10.0 percent, and 10.5 percent) will be adjusted prospectively.

Neither the settlement stipulation nor the associated IPUC order impose a moratorium on Idaho Power filing a general rate case or other form of rate proceeding during the term of the settlement stipulation.

In 2015, Idaho Power recorded a $3.2 million provision against current revenue for sharing with customers, as its Idaho ROE for 2015 was above 10.0 percent. In 2016, Idaho Power recorded no additional ADITC amortization and no provision for sharing with customers, as its 2016 Idaho ROE was between 9.5 percent and 10.0 percent. Accordingly, at December 31, 2016, the full $45 million of additional ADITC remains available for future use under the terms of the settlement stipulation.

In 2016 and 2015, Idaho Power recorded the following for sharing with customers under the October 2014 Idaho settlement stipulations (in millions):

Year	Recorded as Refunds to Customers	Recorded as a Pre-tax Charge to Pension Expense
2016	$—	$—
2015	$3.2	$—

Fixed Cost Adjustment: The Idaho jurisdiction fixed cost adjustment (FCA) mechanism is designed to remove Idaho Power's financial disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. The FCA mechanism is adjusted each year to collect, or refund, the difference between the authorized fixed-cost recovery amount and the actual fixed costs recovered by Idaho Power during the year. The annual change in the FCA recovery is capped at no more than 3 percent of base revenue, with any excess deferred for collection in a subsequent year.

The following table summarizes FCA amounts approved for collection in the prior three FCA years:

FCA Year	Period Rates in Effect	Annual Amount (in millions)
2015	June 1, 2016-May 31, 2017	$28.1
2014	June 1, 2015-May 31, 2016	$16.9

In July 2014, the IPUC opened a docket to allow Idaho Power, the IPUC Staff, and other interested parties to further evaluate the IPUC Staff's concerns regarding the application of the FCA mechanism (including weather-normalization, customer count methodology, rate adjustment cap, and cross-subsidization issues) and whether the FCA is effectively removing Idaho Power's disincentive to aggressively pursue energy efficiency programs. In May 2015, the IPUC approved a settlement stipulation that modified the FCA mechanism by replacing weather-normalized billed sales with actual billed sales in the calculation of the FCA, applicable for the entirety of calendar year 2015 and thereafter, and reflected in FCA charges effective June 1, 2016.

Depreciation Rate Requests

In 2016, Idaho Power conducted a depreciation study of all electric plant-in-service that provided updates to net salvage percentages and service life estimates for all Idaho Power plant assets. Based on the study, in October and November 2016, Idaho Power filed applications with the IPUC and OPUC, respectively, requesting approval to institute revised depreciation rates for Idaho Power's electric plant-in-service and adjust base rates by an aggregate of $7.4 million to reflect the revised depreciation rates applied to electric plant in service balances subject to the most recent general rate cases. The proposed adjustments in these applications are an overall rate increase of 0.6 percent in Idaho and 1.3 percent in Oregon.

At the same time, Idaho Power also filed applications with the IPUC and the OPUC requesting authorization to (a) accelerate depreciation for the North Valmy coal-fired power plant, to allow the plant to be fully depreciated by December 31, 2025, (b) establish a balancing account to track the incremental costs and benefits associated with the accelerated depreciation date, and (c) adjust customer rates to recover the associated incremental annual levelized revenue requirement in the aggregate amount of $29.6 million.

The proposed adjustment in these applications are an overall rate increase of 2.5 percent in Idaho and 1.9 percent in Oregon.

Idaho Power expects the IPUC and the OPUC to enter final orders in both matters prior to June 2017 in Idaho and November 2017 in Oregon.

Western Energy Imbalance Market Costs

Idaho Power plans to participate in a new energy imbalance market implemented in the western United States (Western EIM). In August 2016, Idaho Power filed an application with the IPUC requesting specified regulatory accounting treatment associated with its participation in the Western EIM. In January 2017, the IPUC issued an order authorizing Idaho Power’s requested deferral accounting treatment for costs associated with joining the Western EIM. Idaho Power can defer costs incurred until the earlier of when Idaho Power requests recovery of the costs and the deferral balance or the end of 2018. Recovery of deferred costs will be addressed in a future IPUC proceeding. Idaho Power anticipates that its participation in the Western EIM will commence in the spring of 2018.

Notable Oregon Regulatory Matters

Oregon Base Rate Changes: Oregon base rates were most recently established in a general rate case in 2012. In February 2012, the OPUC issued an order approving a settlement stipulation that provided for a $1.8 million base rate increase, a return on equity of 9.9 percent, and an overall rate of return of 7.757 percent in the Oregon jurisdiction. New rates in conformity with the settlement stipulation were effective March 1, 2012. Subsequently, in September 2012, the OPUC issued an order approving an approximately $3.0 million increase in annual Oregon jurisdiction base rates, effective October 1, 2012, for inclusion of the Langley Gulch power plant in Idaho Power's Oregon rate base.

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 financial and operational data Idaho Power files with the FERC. Idaho Power's OATT rates submitted to the FERC in Idaho Power's four most recent annual OATT Final Informational Filings were as follows:

Applicable Period	OATT Rate (per kW-year)
October 1, 2016 to September 30, 2017	$ 25.52
October 1, 2015 to September 30, 2016	$ 23.43
October 1, 2014 to September 30, 2015	$ 22.48

Idaho Power's current OATT rate is based on a net annual transmission revenue requirement of $127.4 million, which represents the OATT formulaic determination of Idaho Power's net cost of providing OATT-based transmission service.

4. LONG-TERM DEBT

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

	2016	2015
First mortgage bonds:		
6.15% Series due 2019	$ —	$ 100,000
4.50% Series due 2020	130,000	130,000
3.40% Series due 2020	100,000	100,000
2.95% Series due 2022	75,000	75,000
2.50% Series due 2023	75,000	75,000
6.00% Series due 2032	100,000	100,000
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
5.30% 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
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	—
Total first mortgage bonds	1,575,000	1,555,000
Pollution control revenue bonds:		
5.15% Series due 2024(1)	49,800	49,800
5.25% Series due 2026(1)	116,300	116,300
Variable Rate Series 2000 due 2027	4,360	4,360
Total pollution control revenue bonds	170,460	170,460
American Falls bond guarantee	19,885	19,885
Milner Dam note guarantee	1,064	2,127
Unamortized discounts	(4,417)	(4,459)
Total Idaho Power outstanding debt(2)	1,761,992	1,743,013

(1) Humboldt County and Sweetwater County Pollution Control Revenue Bonds are secured by the first mortgage, bringing the total first mortgage bonds outstanding at December 31, 2016, to $1.741 billion.

(2) At December 31, 2016 and 2015, the overall effective cost rate of Idaho Power's outstanding debt was 4.87 percent and 4.96 percent, respectively.

At December 31, 2016, the maturities for the aggregate amount of Idaho Power long-term debt outstanding were as follows (in thousands of dollars):

2017	2018	2019	2020	2021	Thereafter
$ 1,064	$ —	$ —	$ 230,000	$ —	$ 1,535,345

Long-Term Debt Issuances, Maturities, and Availability

On March 10, 2016, Idaho Power issued $120 million in principal amount of 4.05% first mortgage bonds, secured medium-term notes, Series J, maturing on March 1, 2046. On April 11, 2016, Idaho Power redeemed, prior to maturity, $100 million in principal amount of 6.15% first mortgage bonds, medium-term notes, Series H, due April 2019. In accordance with the redemption provisions of the notes, the redemption included Idaho Power's payment of a make-whole premium to the holders of the redeemed notes in the aggregate amount of approximately $14.0 million. Idaho Power used a portion of the net proceeds from the March 2016 sale of first mortgage bonds, medium-term notes to effect the redemption.

On March 6, 2015, Idaho Power issued $250 million in principal amount of 3.65% first mortgage bonds, secured medium-term notes, Series J, maturing on March 1, 2045. On April 23, 2015, Idaho Power redeemed, prior to maturity, $120 million in principal amount of 6.025% first mortgage bonds, secured medium-term notes, Series H, due July 2018. In accordance with the redemption provisions of the notes, the redemption included Idaho Power's payment of a make-whole premium to the holders of the redeemed notes in the aggregate amount of approximately $17.9 million. Idaho Power used a portion of the net proceeds from the March 2015 sale of first mortgage bonds, medium-term notes to effect the redemption.

In April and May 2016, Idaho Power received orders from the IPUC, OPUC, and Wyoming Public Service Commission (WPSC) authorizing Idaho Power to issue and sell from time to time up to $500 million in aggregate principal amount of debt securities and first mortgage bonds, subject to conditions specified in the orders. The order from the IPUC approved the issuance of the securities through May 31, 2019, 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 all-in interest rate limit of 7.0 percent.

On May 20, 2016, IDACORP and Idaho Power filed a joint shelf registration statement with the U.S. Securities and Exchange Commission (SEC), which became effective upon filing, for the offer and sale of, in the case of Idaho Power, an unspecified principal amount of its first mortgage bonds and debt securities. On September 27, 2016, 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 $500 million aggregate principal amount of first mortgage bonds, secured medium term notes, Series K (Series K Notes), under Idaho Power’s Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented (Indenture). At the same time, Idaho Power entered into the Forty-eighth Supplemental Indenture, dated as of September 1, 2016, to the Indenture. The Forty-eighth Supplemental Indenture provides for, among other items, the issuance of up to $500 million in aggregate principal amount of Series K Notes pursuant to the Indenture. As of December 31, 2016, $500 million in principal amount of Series K Notes remained available for issuance under the Indenture.

Mortgage**:** As of December 31, 2016, Idaho Power could issue under its Indenture approximately $1.7 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions. These amounts are further limited by the maximum amount of first mortgage bonds set forth in the Indenture.

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 and clouds 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 five years that immediately follow or precede a particular year.

The Forty-eighth Supplemental Indenture increased the maximum amount of first mortgage bonds issuable by Idaho Power under the Indenture from $2.0 billion to $2.5 billion. The amount issuable is also restricted by property, earnings, and other provisions of the Indenture and supplemental indentures to the Indenture. Idaho Power may amend the Indenture and increase this amount without consent of the holders of the first mortgage bonds. 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.

5. NOTES PAYABLE

Credit Facilities

On November 6, 2015, Idaho Power entered into a Credit Agreement replacing the existing Second Amended and Restated Credit Agreement, dated October 26, 2011, to provide a credit facility that may be used for general corporate purposes and commercial paper backup. Idaho Power's credit facility consists of a revolving line of credit, through the issuance of loans and standby letters of credit, not to exceed the aggregate principal amount at any one time outstanding of $300 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $30 million, and letters of credit in an aggregate principal amount at any time outstanding not to exceed $100 million. Idaho Power has the right to request an increase in the aggregate principal amount of the facilities to $450 million, subject to certain conditions.

The interest rate for any borrowings under the facility is based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, in each case, an applicable margin, provided that the federal funds rate and LIBOR rate will not be less than 0.0 percent. The margin is based on Idaho Power's senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreements. Under the credit facility, Idaho Power pays a facility fee on the commitment based on its credit rating for senior unsecured long-term debt securities. While the credit facility provides for an original maturity date of November 6, 2020, the credit agreement grants Idaho Power the right to request up to two one-year extensions, subject to certain conditions. On November 7, 2016, Idaho Power executed the first extension agreement with the consent of all the lenders, extending the maturity date under the credit agreement to November 5, 2021. No other terms of the credit facility, included the amount of permitted borrowing under the credit agreement, were affected by the extension.

At December 31, 2016, no loans were outstanding under Idaho Power's facility. At December 31, 2016, Idaho Power had regulatory authority to incur up to $450 million in principal amount of short-term indebtedness at any one time outstanding. Balances (in thousands of dollars) and the interest rates of Idaho Power's short-term borrowings were as follows at December 31, 2016, and December 31, 2015:

	Idaho Power	
	2016	**2015**
Commercial paper balances:		
At the end of year	$ 21,800	$ —
Average during the year	$ 438	$ —
Weighted-average interest rate		
At the end of the year	% 1.13%	—%

6. COMMON STOCK

Idaho Power Common Stock

No contributions were made to Idaho Power in 2016 or 2015 and 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 IDACORP is limited to the extent payment of such dividends would violate the covenants in its credit facility or Idaho Power’s Revised 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, 2016, the leverage ratio for Idaho Power was 47 percent. Based on these restrictions, Idaho Power’s dividends were limited to $1.0 billion at December 31, 2016. 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 the company from any material subsidiary. At December 31, 2016, Idaho Power was in compliance with those covenants.

Idaho Power’s Revised 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, 2016, Idaho Power's common equity capital was 53 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 Federal Power Act (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. STOCK-BASED COMPENSATION

Through its Parent Company IDACORP, Idaho Power has two share-based compensation plans -- the 2000 Long-Term Incentive and Compensation Plan (LTICP) and the 1994 Restricted Stock Plan (RSP). The RSP was terminated effective February 9, 2017. The LTICP (for officers, key employees, and directors) permits the grant of stock options, restricted stock, performance shares, performance units, and several other types of stock-based awards. At December 31, 2016, the maximum number of shares available under the LTICP and RSP were 934,781 and 15,796, respectively, excluding (i) issued but unvested performance-based restricted shares and (ii) issued but unvested time-based restricted shares.

Stock Awards: Restricted stock awards have three-year vesting periods and entitle the recipients to dividends and voting rights. Unvested shares 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, based on the number of shares expected to vest.

Performance-based restricted stock awards have three-year vesting periods and entitle the recipients to voting rights. Unvested shares 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 150 percent of the target award for awards granted prior to 2015 and from zero to 200 percent of the target award for awards granted in 2015 and 2016. Dividends 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 number of shares expected to vest. 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 and performance share activity is presented below. Share amounts represent the shares of IDACORP common stock:

	Idaho Power	
	Number of	Weighted-Average Grant Date Fair Value
Nonvested shares at January 1, 2016	228,790	$ 52.44
Shares granted	113,708	64.18
Shares forfeited	(24,699)	65.75
Shares vested	(118,273)	44.32
Nonvested shares at December 31, 2016	199,526	$ 61.51

The total fair value of shares vested was $8.3 million in 2016 and $8.3 million in 2015. At December 31, 2016, Idaho Power had $4.9 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. These costs are expected to be recognized over a weighted-average period of 1.73 years. IDACORP uses original issue and/or treasury shares for these awards.

In 2016, a total of 12,681 shares of IDACORP common stock were awarded to directors of IDACORP and Idaho Power at a grant date fair value of $70.96 per share. Directors elected to defer receipt of 4,931 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 share of the compensation cost recognized in income and the tax benefits resulting from these plans (in thousands of dollars):

	Idaho Power	
	2016	2015
Compensation cost	$ 5,494	$ 5,221
Income tax benefit	2,148	2,042

No equity compensation costs have been capitalized. These costs are primarily reported within other operations and maintenance expense in the consolidated statements of income.

8. COMMITMENTS

Purchase Obligations

At December 31, 2016, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2017	2018	2019	2020	2021	Thereafter
Cogeneration and power production	$ 228,545	$ 235,366	$ 229,450	$ 229,473	$ 235,922	$ 3,150,212
Fuel	56,534	22,070	8,948	8,433	8,399	100,978

As of December 31, 2016, Idaho Power had 945 MW nameplate capacity of PURPA-related projects on-line, with an additional 178 MW nameplate capacity of projects projected to be on-line in 2017 and an additional 9 MW expected to be added in 2019. The power purchase contracts for these projects have original contract terms ranging from one to 35 years. Idaho Power's expenses associated with PURPA-related projects were approximately $154 million in 2016 and $131 million in 2015.

Idaho Power also has the following long-term commitments for lease guarantees, equipment, maintenance and services, and industry related fees (in thousands of dollars):

	2017	2018	2019	2020	2021	Thereafter
Operating leases	$ 3,339	$ 4,171	$ 4,237	$ 4,076	$ 4,038	$ 29,218
Equipment, maintenance, and service agreements	26,884	12,435	6,185	6,871	3,421	51,085
FERC and other industry-related fees	12,508	12,444	8,434	5,744	5,744	28,720

Idaho Power’s expense for operating leases was approximately $4.9 million in 2016 and $4.4 million in 2015.

Guarantees

Through a self-bonding mechanism, 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, was $71 million at December 31, 2016, representing IERCo's one-third share of BCC's total reclamation obligation. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2016, the value of the reclamation trust fund was $78 million. During 2016, the reclamation trust fund distributed approximately $6 million for reclamation activity costs associated with the BCC surface mine. 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, all of which are made 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 enters 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 evaluates the likelihood of incurring costs under such indemnities based on their historical experience and the evaluation of the specific indemnities. As of December 31, 2016, 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 consolidated balance sheet with respect to these indemnification obligations.

9. CONTINGENCIES

Idaho Power has in the past and expects in the future to become involved in various claims, controversies, disputes, and other contingent matters, including the items described below. Some of these claims, controversies, disputes, and other contingent matters 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. In such cases, there may be a possible exposure to loss in excess of any amounts accrued. Idaho Power monitors those matters for developments that could affect the likelihood of a loss and the accrued amount, if any, and adjust the amount as appropriate. 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.

Western Energy Proceedings

High prices for electricity, energy shortages, and blackouts in California and in the western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings to consider requiring refunds and other forms of disgorgement from energy sellers. Idaho Power and IESCo (as successor to IDACORP Energy L.P.) believe that the current state of the FERC's orders and the settlement releases they have obtained, including a settlement Idaho Power and IESCo executed in December 2016 and approved by the FERC relating to the California energy market proceedings, will eliminate or restrict potential future claims that might result from the remaining proceedings. As Idaho Power believes that its participation in the California and western wholesale market proceedings has effectively concluded, Idaho Power expects that these matters will not have a material adverse effect on its respective results of operations or financial condition in future periods.

Hoku Corporation Bankruptcy Claims

On June 26, 2015, the trustee in the Hoku Corporation chapter 7 bankruptcy case (*In Re: Hoku Corporation*, United States Bankruptcy Court, District of Idaho, Case No. 13-40838 JDP) filed a complaint against Idaho Power, alleging that specified payments made by Hoku Corporation to Idaho Power in the six years prior to Hoku Corporation's bankruptcy filing in July 2013 should be recoverable by the trustee as constructive fraudulent transfers. Hoku Corporation was the parent entity of Hoku Materials, Inc., with which Idaho Power had an electric service agreement approved by the IPUC in March 2009. Under the electric service agreement, Idaho Power agreed to provide electric service to a polysilicon production facility under construction by Hoku Materials in the state of Idaho. Idaho Power also had agreements with Hoku Materials pertaining to the design and construction of apparatus for the provision of electric service to the polysilicon plant. The trustee's complaint against Idaho Power requested recovery from Idaho Power in amounts up to approximately $36 million. The complaint alleged that the payments made by Hoku Corporation to Idaho Power were subject to recovery by the trustee on the basis that Hoku Corporation was insolvent at the time of the payments and did not have any legal or equitable title in the polysilicon plant or liability for Hoku Materials' debts, and thus did not receive reasonably equivalent value for the payments it made for or on behalf of Hoku Materials. In September 2016, the bankruptcy judge issued an oral opinion granting Idaho Power's and other parties' motion for substantive consolidation of Hoku Corporation and Hoku Materials, which consolidated the bankruptcies of Hoku Corporation and Hoku Materials. On December 20, 2016, the bankruptcy judge entered an order of dismissal, with prejudice, of the complaint against Idaho Power, which effectively ended Idaho Power's participation in the adversary proceedings.

Other Proceedings

Idaho Power is party to legal claims and legal and regulatory actions and proceedings in the ordinary course of business that are in addition to those discussed above and, as noted above, record an accrual for associated loss contingencies when they are probable and reasonably estimable. As of the date of this report, the company believes that resolution of those matters will not have a material adverse effect on its consolidated financial statements. Idaho Power is also actively monitoring various pending environmental regulations 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. However, Idaho Power does believe that future capital investment for infrastructure and modifications to its electric system facilities could be significant to comply with these regulations.

10. 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 two pension plans–a noncontributory defined benefit pension plan (pension plan) and two nonqualified defined benefit pension plans for certain senior management employees called the Security Plan for Senior Management Employees I and Security Plan for Senior Management Employees II (together, 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.

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 2016 and 2015 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.

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

	Pension Plan		SMSP	
	2016	2015	2016	2015
Change in projected benefit obligation:				
Benefit obligation at January 1	$ 835,523	$ 844,812	$ 95,389	$ 94,410
Service cost	32,019	33,164	1,228	1,689
Interest cost	37,813	35,171	4,275	3,868
Actuarial loss (gain)	22,640	(47,952)	2,933	(352)
Plan amendment	81	—	120	—
Benefits paid	(33,016)	(29,672)	(4,375)	(4,226)
Projected benefit obligation at December 31	895,060	835,523	99,570	95,389
Change in plan assets:				
Fair value at January 1	559,616	559,719	—	—
Actual return on plan assets	40,968	(9,431)	—	—
Employer contributions	40,000	39,000	—	—
Benefits paid	(33,016)	(29,672)	—	—
Fair value at December 31	607,568	559,616	—	—
Funded status at end of year	$ (287,492)	$ (275,907)	$ (99,570)	$ (95,389)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (4,733)	$ (4,423)
Noncurrent liabilities	(287,492)	(275,907)	(94,837)	(90,966)
Net amount recognized	$ (287,492)	$ (275,907)	$ (99,570)	$ (95,389)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 263,634	253,212	33,660	34,260
Prior service cost	96	74	625	673
Subtotal	263,730	253,286	34,285	34,933
Less amount recorded as regulatory asset	(263,730)	(253,286)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 34,285	$ 34,933
Accumulated benefit obligation	$ 766,367	$ 714,994	$ 91,146	$ 86,838

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 $78 million and $69 million at December 31, 2016 and 2015, respectively, and is reflected in Investments and in Company-owned life insurance on the consolidated balance sheets.

The following table shows the components of net periodic benefit 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	
	2016	2015	2016	2015
Service cost	$ 32,019	$ 33,164	$ 1,228	$ 1,689
Interest cost	37,813	35,171	4,275	3,868
Expected return on assets	(42,081)	(42,310)	—	—
Amortization of net loss	13,331	13,927	3,532	4,195
Amortization of prior service cost	59	221	168	185
Net periodic pension cost	41,141	40,173	9,203	9,937
Adjustments due to the effects of regulation(1)	(22,181)	(21,173)	—	—
Net periodic benefit cost recognized for financial reporting	$ 18,960	$ 19,000	$ 9,203	$ 9,937

(1) Net periodic benefit costs for the pension plan are recognized for financial reporting based upon the authorization of each regulatory jurisdiction in which Idaho Power operates. Under IPUC order, income statement recognition of pension plan costs is deferred until costs are recovered through rates.

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

	Pension Plan		SMSP	
	2016	**2015**	**2016**	**2015**
Actuarial (loss) gain during the year	$ (23,753)	$ (3,790)	$ (2,933)	$ 353
Reclassification adjustments for:				
Amortization of net loss	13,331	13,927	3,532	4,195
Plan amendment service cost	(81)	—	(120)	—
Amortization of prior service cost	59	221	168	185
Adjustment for deferred tax effects	4,083	(4,050)	(253)	(1,851)
Adjustment due to the effects of regulation	6,361	(6,308)	—	—
Other comprehensive income recognized related to pension benefit plans	$ —	$ —	$ 394	$ 2,882

In 2017, Idaho Power expects to recognize as components of net periodic benefit cost $16.6 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2016, relating to the pension plan and SMSP. This amount consists of $13.5 million of amortization of net loss for the pension plan and $3.0 million of amortization of net loss and $0.1 million of amortization of prior service cost for the SMSP.

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

	2017	2018	2019	2020	2021	2022-2026
Pension Plan	$ 32,592	$ 34,957	$ 37,375	$ 39,938	$ 42,477	$ 248,151
SMSP	4,829	4,630	4,594	5,199	4,843	26,976

As of December 31, 2016, Idaho Power's minimum required contributions to the pension plan are estimated to be zero in 2017, though Idaho Power plans to contribute between $20 million and $40 million to the pension plan during 2017 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):

	2016	2015
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 62,393	$ 65,999
Service cost	1,116	1,235
Interest cost	2,766	2,678
Actuarial loss (gain)	1,550	(5,008)
Benefits paid(1)	(3,949)	(2,511)
Benefit obligation at December 31	63,876	62,393
Change in plan assets:		
Fair value of plan assets at January 1	35,566	38,375
Actual return on plan assets	2,425	85
Employer contributions(1)	957	(383)
Benefits paid(1)	(3,949)	(2,511)
Fair value of plan assets at December 31	34,999	35,566
Funded status at end of year (included in noncurrent liabilities)	$ (28,877)	$ (26,827)

(1) Contributions and benefits paid are each net of $3.7 million and $3.5 million of plan participant contributions, and $0.3 million and $0.3 million of Medicare Part D subsidy receipts for 2016 and 2015, respectively.

Amounts recognized in accumulated other comprehensive income consist of the following (in thousands of dollars):

	2016	2015
Net gain	$ (55)	$ (1,654)
Prior service cost	104	130
Subtotal	49	(1,524)
Less amount recognized in regulatory assets	(49)	1,524
Net amount recognized in accumulated other comprehensive income	$ —	$ —

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

	2016	2015
Service cost	$ 1,116	$ 1,235
Interest cost	2,766	2,678
Expected return on plan assets	(2,474)	(2,680)
Amortization of prior service cost	26	15
Net periodic postretirement benefit cost	$ 1,434	$ 1,248

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

	2016	2015
Actuarial (loss) gain during the year	$ (1,600)	$ 2,413
Reclassification adjustments for amortization of prior service cost	26	15
Adjustment for deferred tax effects	615	(949)
Adjustment due to the effects of regulation	959	(1,479)
Other comprehensive income related to postretirement benefit plans	$ —	$ —

Medicare Act: The Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law in December 2003 and established a prescription drug benefit under Medicare Part D, as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare's prescription drug coverage.

The following table summarizes the expected future benefit payments of the postretirement benefit plan and expected Medicare Part D subsidy receipts (in thousands of dollars):

	2017	2018	2019	2020	2021	2022-2026
Expected benefit payments	$ 3,980	$ 4,040	$ 4,070	$ 4,100	$ 4,120	$ 20,620
Expected Medicare Part D subsidy receipts	370	410	450	480	520	3,240

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:

	Pension Plan		SMSP		Postretirement Benefits	
	2016	2015	2016	2015	2016	2015
Discount rate	4.45%	4.60%	4.45%	4.60%	4.45%	4.60%
Rate of compensation increase(1)	4.11%	4.11%	4.75%	4.50%	—	—
Medical trend rate	—	—	—	—	8.3%	9.7%
Dental trend rate	—	—	—	—	5.0%	5.0%
Measurement date	12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015

(1) The 2016 rate of compensation increase assumption for the pension plan includes an inflation component of 2.50% plus a 1.61% composite merit increase component that is based on employees' years of service. Merit salary increases are assumed to be 8.0% for employees in their first year of service and scale down to 0% 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:

	Pension Plan		SMSP		Postretirement Benefits	
	2016	**2015**	**2016**	**2015**	**2016**	**2015**
Discount rate	4.60%	4.25%	4.60%	4.20%	4.60%	4.20%
Expected long-term rate of return on assets	7.50%	7.50%	—	—	7.25%	7.25%
Rate of compensation increase	4.11%	4.11%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	8.3%	9.7%
Dental trend rate	—	—	—	—	5.0%	5.0%

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 8.3 percent in 2016 and is assumed to decrease to 6.8 percent in 2017, 5.3 percent in 2018, 5.2 percent in 2019 and to gradually decrease to 4.5 percent by 2096. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent, or equal to the medical trend rate if lower, for all years. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2016 (in thousands of dollars):

	One-Percentage-Point	
	Increase	**Decrease**
Effect on total of cost components	$ 382	$ (280)
Effect on accumulated postretirement benefit obligation	3,687	(2,841)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2016, for the pension asset portfolio by asset class is set forth below:

Asset Class	**Target**	**Actual Allocation December 31, 2016**
Debt securities	24%	22%
Equity securities	54%	56%
Real estate	6%	7%
Other plan assets	16%	15%
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 pensioners.

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 bond allocations sufficient to cover at least five years of benefit payments and cash allocations sufficient to cover the current year 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, core real estate funds, private equity funds, and cash and cash equivalents. With the exception of real estate holdings 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 low interest rate environment, current rate-of-return expectations are lower than the nominal returns generated over the past 20 years when interest rates were generally much 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. 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, 2016				
Cash and cash equivalents	$ 28,632	—	—	$ 28,632
Short-term bonds	11,198	—	—	11,198
Intermediate bonds	11,904	88,734	—	100,638
Long-term bonds	—	20,573	—	20,573
Equity Securities: Large-Cap	80,582	—	—	80,582
Equity Securities: Mid-Cap	68,634	—	—	68,634
Equity Securities: Small-Cap	53,766	—	—	53,766
Equity Securities: Micro-Cap	29,671	—	—	29,671
Equity Securities: International	7,782	—	—	7,782
Equity Securities: Emerging Markets	9,204	—	—	9,204
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Equity Securities: International	—	—	—	64,930
Equity Securities: Emerging Markets	—	—	—	24,443
Real estate	—	—	—	41,907
Private market investments	—	—	—	33,713
Commodities fund	—	—	—	31,895
Total	$ 301,373	$ 109,307	—	$ 607,568
Postretirement plan assets(1)	$ 28	$ 34,971	—	$ 34,999
Assets at December 31, 2015				
Cash and cash equivalents	$ 10,519	—	—	$ 10,519
Short-term bonds	11,023	—	—	11,023
Intermediate bonds	11,499	92,742	—	104,241
Long-term bonds	—	21,747	—	21,747
Equity Securities: Large-Cap	73,489	—	—	73,489
Equity Securities: Mid-Cap	64,397	—	—	64,397
Equity Securities: Small-Cap	47,777	—	—	47,777
Equity Securities: Micro-Cap	22,186	—	—	22,186
Equity Securities: International	7,698	—	—	7,698
Equity Securities: Emerging Markets	9,679	—	—	9,679
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Equity Securities: International	—	—	—	59,787
Equity Securities: Emerging Markets	—	—	—	23,167
Real estate	—	—	—	39,035
Private market investments	—	—	—	37,316
Commodities fund	—	—	—	27,555
Total	$ 258,267	$ 114,489	—	$ 559,616
Postretirement plan assets(1)	$ 16	$ 35,550	—	$ 35,566

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

For the year ended December 31, 2016 and December 31, 2015, there were no material transfers into or out of Levels 1, 2, or 3 other than the adoption of ASU 2015-07, *Fair Value Measurement (Topic 820)* **-** *Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)*, which removed from the fair value hierarchy, investments for which the practical expedient is used to measure fair value at net asset value (NAV). In prior years, certain investments were measured using NAV as a practical expedient for fair value, and these amounts were included as level 2 and 3 items in the fair value hierarchy. The requirements of this ASU were adopted retrospectively; therefore, the 2015 amounts have been reclassified to conform to the 2016 presentation. Because these amounts are no longer included in the fair value hierarchy as level 3 items, the level 3 reconciliations are no longer applicable and have been excluded from this footnote.

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

Level 2 Bonds: These investments represent U.S. government, agency bonds, and corporate bonds. The U.S. 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 the international, emerging markets equity securities, and commodites fund measured at NAV, are not publicly traded, and therefore no publicly quoted market price is readily available. The value 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 5 to 7 days.

Real Estate: Real estate holdings represent investments in open-ended 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 open-ended real estate funds also furnish annual audited financial statements that are also used to further validate the information provided. Redemptions 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.

Private Market Investments: Private market investments represent two categories: fund of hedge funds and venture capital 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. Some hedge fund strategies utilize securities with readily available market prices, while others utilize less liquid investment vehicles that are valued based on unobservable inputs including cost, operating results, recent funding activity, or comparisons with similar investment vehicles. Redemptions are available on a quarterly basis with 70 days written notice. Redemptions will be processed at the quarterly NAV or fair value within 60 days following quarter end. In the event of a full redemption, a reserve amount of 5% to 10% of the redemption amount may be held in reserve until the audited financial statements of the fund are published. This allows the fund to adjust the redemption so that other fund holders are not adversely impacted. 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.

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 $8 million and $7 million in 2016 and 2015, 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 benefit amounts included in other deferred credits on Idaho Power’s consolidated balance sheet at both December 31, 2016 and 2015, were $2 million.

11. 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, 2016 and 2015 (in thousands of dollars):

	2016		2015	
	Balance	**Avg Rate**	**Balance**	**Avg Rate**
Production	$ 2,551,823	2.40%	$ 2,422,175	2.46%
Transmission	1,120,903	2.02%	1,077,065	2.01%
Distribution	1,637,131	2.72%	1,578,445	2.72%
General and Other	422,187	5.49%	407,779	5.62%
Total in service	5,732,044	2.64%	5,485,464	2.68%
Accumulated provision for depreciation	(2,175,086)		(2,097,432)	
In service - net	$ 3,556,958		$ 3,388,032	

At December 31, 2016, Idaho Power's construction work in progress balance of $405 million included relicensing costs of $249 million for the Hells Canyon Complex (HCC), Idaho Power's largest hydroelectric complex. The IPUC authorizes Idaho Power to include in its Idaho jurisdiction rates approximately $6.5 million annually ($10.7 million when grossed-up for the effect of income taxes) of AFUDC relating to the HCC relicensing project. Collecting these amounts now will reduce the amount collected in the future once the HCC relicensing costs are approved for recovery in base rates. At December 31, 2016, Idaho Power's accumulated provision for rate refunds for collection of AFUDC relating to the HCC was $103 million.

Idaho Power's ownership interest in three 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 Consolidated 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, 2016 (in thousands of dollars):

Name of Plant	Location	Utility Plant in Service	Construction Work in Progress	Accumulated Provision for Depreciation	Ownership	MW[1]
Jim Bridger Units 1-4	Rock Springs, WY	$ 710,910	$ 5,972	$ 302,291	33	771
Boardman	Boardman, OR	82,419	34	67,568	10	64
Valmy Units 1 and 2	Winnemucca, NV	410,390	1,373	189,557	50	284

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

IERCo, Idaho Power's wholly-owned subsidiary, is a joint venturer in BCC. Idaho Power's coal purchases from the joint venture were $93 million in 2016 and $93 million in 2015.

Idaho Power has contracts to purchase the energy from four PURPA qualified facilities that are 50 percent owned by Ida-West. Idaho Power's power purchases from these facilities were $8 million in 2016 and $8 million in 2015.

12. 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 records regulatory assets or liabilities instead of accretion, depreciation, and gains or losses, as approved by the IPUC. The regulatory assets recorded under this order do not earn a return on investment. Beginning June 1, 2012, accretion, depreciation, and gains or losses related to the Boardman generating facility have been exempted from such regulatory treatment as Idaho Power is now collecting amounts related to the decommissioning of Boardman in rates.

Idaho Power's recorded AROs relate to the removal of polychlorinated biphenyl-contaminated equipment at its distribution facilities and the reclamation and removal costs at its jointly-owned coal-fired generation facilities. In 2016, changes in estimates at the coal-fired generation facilities resulted in a net increase of $1.8 million in the recorded AROs.

Idaho Power also has additional AROs associated with its transmission system, hydroelectric facilities, natural gas-fired generation facilities, and jointly owned coal-fired 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 consolidated financial statements.

The regulated operations of Idaho Power also collect removal costs in rates for certain assets that do not have associated AROs. Idaho Power is required to redesignate these removal costs as regulatory liabilities. See Note 3 for the removal costs recorded as regulatory liabilities on Idaho Power's consolidated balance sheets as of December 31, 2016 and 2015.

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

	2016	2015
Balance at beginning of year	$ 26,153	$ 21,930
Accretion expense	1,031	993
Revisions in estimated cash flows	1,759	5,043
Liability settled	(2,686)	(1,813)
Balance at end of year	$ 26,257	$ 26,153

13. INVESTMENTS

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

	2016	2015
Idaho Power investments:		
IERCO	$ 77,131	$ 84,137
Exchange traded short-term bond funds and cash equivalents	23,908	24,459
Executive deferred compensation plan investments	111	102
Total Idaho Power investments	$ 101,150	$ 108,698

Investments in Equity Securities

Investments in securities classified as available-for-sale securities are reported at fair value. Any unrealized gains or losses on available-for-sale securities are included in income, as the fair value option has been elected for these instruments. Unrealized gains and losses on available-for-sale securities were immaterial at December 31, 2016 and December 31, 2015. The following table summarizes sales of available-for-sale securities (in thousands of dollars):

	2016	2015
Proceeds from sales	$ 15,693	$ 34,243
Gross realized gains from sales	54	—
Gross realized losses from sales	—	—

At the end of each reporting period, Idaho Power analyzes securities in loss positions to determine whether they have experienced a decline in market value that is considered other-than-temporary. At December 31, 2016 and December 31, 2015, there were no indicators of other-than-temporary impairment related to Idaho Power's investments.

14. 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 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 below.

The table below presents the gains and losses on derivatives not designated as hedging instruments for the years ended December 31, 2016 and 2015 (in thousands of dollars):

	Location of Realized Gain/(Loss) on Derivatives Recognized in Income	**Gain/(Loss) on Derivatives Recognized in Income[1]**	
		2016	**2015**
Financial swaps	Off-system sales	$ 1,405	$ 2,882
Financial swaps	Purchased power	586	748
Financial swaps	Fuel expense	(1,947)	(6,045)
Financial swaps	Other operations and maintenance	(161)	(50)
Forward contracts	Off-system sales	—	—
Forward contracts	Purchased power	31	(6)
Forward contracts	Fuel expense	139	54

(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 off-system sales 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 operations and maintenance expense. See Note 15 for additional information concerning the determination of fair value for Idaho Power’s assets and liabilities from price risk management activities.

Derivative Instrument Summary

The table below presents the fair values and locations of 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 at December 31, 2016 and 2015 (in thousands of dollars):

		Asset Derivatives			Liability Derivatives		
	Balance Sheet	Gross Fair Value	Amounts	Net	Gross Fair Value	Amounts	Net
December 31, 2016							
Current:							
Financial swaps	Other current assets	$ 8,134	$ (2,183) (1)	$ 5,951	$ 302	$ (302)	$ —
Total		$ 8,134	$ (2,183)	$ 5,951	$ 302	$ (302)	$ —
December 31, 2015							
Current:							
Financial swaps	Other current assets	$ 999	$ (785)	$ 214	$ 785	$ (785)	$ —
Financial swaps	Other current liabilities	177	(177)	—	5,146	(177)	4,969
Forward contracts	Other current assets	64	—	64	—	—	—
Forward contracts	Other current liabilities	—	—	—	3	—	3
Long-term:							
Financial swaps	Other assets	148	(22)	126	22	(22)	—
Total		$ 1,388	$ (984)	$ 404	$ 5,956	$ (984)	$ 4,972

(1) Current asset derivative amounts offset include $1.9 million of collateral payable for the period ending December 31, 2016.

The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2016 and 2015 (in thousands of units):

		December 31,	
Commodity	Units	2016	2015
Electricity purchases	MWh	217	357
Electricity sales	MWh	135	120
Natural gas purchases	MMBtu	6,604	11,597
Natural gas sales	MMBtu	70	78
Diesel purchases	Gallons	1,188	1,068

Credit Risk

At December 31, 2016, 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, or letters of credit from counterparties or their affiliates, as deemed necessary. Idaho Power's physical power contracts are commonly under Western Systems Power Pool 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 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 Investors Service 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, 2016, was $0.3 million. Idaho Power posted no cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2016, Idaho Power would have been required to pay or post collateral to its counterparties up to an additional $2.7 million to cover open liability positions as well as completed transactions that have not yet been paid.

15. FAIR VALUE MEASUREMENTS

Idaho Power has categorized its 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 has 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 are based on quoted market prices adjusted for location using corroborated, observable market data.

- 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. An item recorded at fair value is reclassified among levels when changes in the nature of valuation inputs cause the item to no longer meet the criteria for the level in which it was previously categorized. There were no transfers between levels or material changes in valuation techniques or inputs during the years ended December 31, 2016 and 2015.

The following table presents information about Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31, 2016 and 2015 (in thousands of dollars):

	December 31, 2016				**December 31, 2015**			
	Level 1	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets:								
Money market funds								
Money market funds	$29,967	$—	$—	$29,967	$10,000	$—	$—	$10,000
Derivatives	5,951	—	—	5,951	340	64	—	404
Trading securities: Equity securities	111	—	—	111	102	—	—	102
Available-for-sale securities: Equity securities	23,908	—	—	23,908	24,459	—	—	24,459
Liabilities:								
Derivatives	$ —	$ —	$ —	$ —	$ 286	$ 4,686	$ —	$ 4,972

Idaho Power's derivatives are contracts entered into as part of its management of loads and resources. Electricity derivatives are valued on the Intercontinental Exchange (ICE) with quoted prices in an active market. Natural gas and diesel derivative valuations are performed using New York Mercantile Exchange (NYMEX) and ICE pricing, adjusted for location basis, which are also quoted under NYMEX and ICE pricing. Trading securities consist of employee-directed investments held in a Rabbi trust and are related to an executive deferred compensation plan. Available-for-sale securities are related to the SMSP, are held in a Rabbi trust, and are actively traded money market and exchange-traded funds with quoted prices in active markets.

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, 2016 and 2015, using available market information and appropriate valuation methodologies (in thousands of dollars):

	December 31, 2016		December 31, 2015	
	Carrying Amount	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
	(thousands of dollars)			
Idaho Power				
Liabilities:				
Long-term debt[1]	$ 1,745,678	$ 1,858,666	$ 1,726,474	$ 1,813,243

[1] Notes receivable and long-term debt are categorized as Level 3 and Level 2, respectively, of the fair value hierarchy, as defined earlier in this Note 16.

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.

16. 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 accumulated other comprehensive income (AOCI), net of tax, during the years ended December 31, 2016 and 2015 (in thousands of dollars). Items in parentheses indicate reductions to AOCI.

	Year Ended December 31,	
	2016	**2015**
Defined benefit pension items		
Balance at beginning of period	$ (21,276)	$ (24,158)
Other comprehensive income before reclassifications	(1,859)	214
Amounts reclassified out of AOCI	2,253	2,668
Net current-period other comprehensive income	394	2,882
Balance at end of period	$ (20,882)	$ (21,276)

The table below presents amounts reclassified out of components of AOCI and the income statement location of those amounts reclassified during the years ended December 31, 2016 and 2015 (in thousands of dollars). Items in parentheses indicate increases to net income.

	Amount Reclassified from AOCI	
	Year Ended December 31,	
	2016	2015
Amortization of defined benefit pension items[1]		
Prior service cost	$ 168	$ 185
Net loss	3,532	4,195
Total before tax	3,700	4,380
Tax benefit[2]	(1,447)	(1,712)
Net of tax	2,253	2,668
Total reclassification for the period	$ 2,253	$ 2,668

(1) Amortization of these items is included in Idaho Power's consolidated income statements in other expense, net.

(2) The tax benefit is included in income tax expense in the consolidated income statements of Idaho Power.

17. 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 $0.8 million in 2016 and $0.9 million in 2015.

Ida-West: Idaho Power purchases all of the power generated by four of Ida-West’s hydroelectric projects located in Idaho. Idaho Power paid Ida-West $8 million in both 2016 and 2015.

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)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	5,731,292,950	5,731,292,950
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,731,292,950	5,731,292,950
9	Leased to Others		
10	Held for Future Use	7,440,603	7,440,603
11	Construction Work in Progress	405,068,524	405,068,524
12	Acquisition Adjustments	750,893	750,893
13	Total Utility Plant (8 thru 12)	6,144,552,970	6,144,552,970
14	Accum Prov for Depr, Amort, & Depl	2,175,085,495	2,175,085,495
15	Net Utility Plant (13 less 14)	3,969,467,475	3,969,467,475
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,150,749,270	2,150,749,270
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	24,336,225	24,336,225
22	Total In Service (18 thru 21)	2,175,085,495	2,175,085,495
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	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,175,085,495	2,175,085,495

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/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 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)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	5,703	
3	(302) Franchises and Consents	29,759,682	272,993
4	(303) Miscellaneous Intangible Plant	28,493,799	2,169,391
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	58,259,184	2,442,384
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,730,471	-8,050
9	(311) Structures and Improvements	153,408,729	-1,287,206
10	(312) Boiler Plant Equipment	682,889,150	83,922,600
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	162,544,079	4,905,944
13	(315) Accessory Electric Equipment	70,701,789	1,488,262
14	(316) Misc. Power Plant Equipment	17,503,886	1,707,969
15	(317) Asset Retirement Costs for Steam Production	13,930,061	1,381,822
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,102,708,165	92,111,341
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	31,223,914	220,924
28	(331) Structures and Improvements	175,996,371	3,223,850
29	(332) Reservoirs, Dams, and Waterways	269,959,842	1,896,784
30	(333) Water Wheels, Turbines, and Generators	211,679,356	31,349,747
31	(334) Accessory Electric Equipment	58,474,318	2,456,072
32	(335) Misc. Power PLant Equipment	22,796,263	1,824,175
33	(336) Roads, Railroads, and Bridges	10,880,502	-1,514
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	781,010,566	40,970,038
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,690,006	
38	(341) Structures and Improvements	142,711,065	498,927
39	(342) Fuel Holders, Products, and Accessories	10,452,547	
40	(343) Prime Movers	218,960,892	10,912,860
41	(344) Generators	66,531,876	
42	(345) Accessory Electric Equipment	91,098,988	59,863
43	(346) Misc. Power Plant Equipment	6,010,475	229,891
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	538,455,849	11,701,541
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,422,174,580	144,782,920

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			5,703		2
			30,032,675		3
7,960,965			22,702,225		4
7,960,965			52,740,603		5
					6
					7
			1,722,421		8
560,561			151,560,962		9
8,667,325			758,144,425		10
					11
1,728,354			165,721,669		12
56,504			72,133,547		13
1,708,323			17,503,532		14
			15,311,883		15
12,721,067			1,182,098,439		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			31,444,838		27
197,235			179,022,986		28
94,468			271,762,158		29
1,371,762			241,657,341		30
553,305			60,377,085		31
105,965			24,514,473		32
36,404			10,842,584		33
					34
2,359,139			819,621,465		35
					36
			2,690,006		37
42,002			143,167,990		38
			10,452,547		39
			229,873,752		40
			66,531,876		41
12,000			91,146,851		42
			6,240,366		43
					44
54,002			550,103,388		45
15,134,208			2,551,823,292		46

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	36,379,079	814,143
49	(352) Structures and Improvements	77,780,246	1,851,599
50	(353) Station Equipment	407,602,629	7,067,324
51	(354) Towers and Fixtures	184,628,055	13,550,729
52	(355) Poles and Fixtures	158,380,194	17,657,509
53	(356) Overhead Conductors and Devices	211,904,657	8,556,373
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	390,266	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,077,065,126	49,497,677
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	5,300,524	647,447
61	(361) Structures and Improvements	34,175,353	2,842,549
62	(362) Station Equipment	216,853,729	6,762,998
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	246,985,666	11,415,269
65	(365) Overhead Conductors and Devices	129,331,468	3,739,895
66	(366) Underground Conduit	48,322,609	1,861,831
67	(367) Underground Conductors and Devices	230,143,168	15,383,360
68	(368) Line Transformers	515,652,279	27,403,469
69	(369) Services	58,770,764	1,191,980
70	(370) Meters	85,247,458	6,296,981
71	(371) Installations on Customer Premises	2,954,458	127,799
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,543,249	74,540
74	(374) Asset Retirement Costs for Distribution Plant	164,191	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,578,444,916	77,748,118
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	16,578,582	643,905
87	(390) Structures and Improvements	110,924,656	7,736,358
88	(391) Office Furniture and Equipment	46,692,083	5,534,502
89	(392) Transportation Equipment	75,878,863	9,368,330
90	(393) Stores Equipment	2,255,403	407,050
91	(394) Tools, Shop and Garage Equipment	8,021,556	925,406
92	(395) Laboratory Equipment	12,703,819	841,679
93	(396) Power Operated Equipment	15,082,035	612,102
94	(397) Communication Equipment	55,415,200	3,452,061
95	(398) Miscellaneous Equipment	5,967,704	617,357
96	SUBTOTAL (Enter Total of lines 86 thru 95)	349,519,901	30,138,750
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)	349,519,901	30,138,750
100	TOTAL (Accounts 101 and 106)	5,485,463,707	304,609,849
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)	5,485,463,707	304,609,849

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			37,193,222		48
91,962			79,539,883		49
3,380,833			411,289,120		50
76,185			198,102,599		51
865,060			175,172,643		52
1,246,222			219,214,808		53
					54
					55
			390,266		56
					57
5,660,262			1,120,902,541		58
					59
			5,947,971		60
33,536			36,984,366		61
1,259,863			222,356,864		62
					63
2,242,023			256,158,912		64
1,796,023			131,275,340		65
389,672			49,794,768		66
1,876,265			243,650,263		67
6,505,273			536,550,475		68
491,357			59,471,387		69
4,284,884			87,259,555		70
65,280			3,016,977		71
					72
117,336			4,500,453		73
			164,191		74
19,061,512			1,637,131,522		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
46,532			17,175,955		86
211,661			118,449,353		87
3,144,715			49,081,870		88
3,817,493			81,429,700		89
42,456			2,619,997		90
280,796			8,666,166		91
523,133			13,022,365		92
609,100			15,085,037		93
2,274,049			56,593,212		94
13,724			6,571,337		95
10,963,659			368,694,992		96
					97
					98
10,963,659			368,694,992		99
58,780,606			5,731,292,950		100
					101
					102
					103
58,780,606			5,731,292,950		104

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	Boise Operations Center	12/31/82	2017	655,550
3	Production			109,961
4	Transmission Stations			423,089
5	Transmission Lines			195,489
6	Distribution Stations			973,839
7	Beacon Light Substation	12/30/02	2020	465,662
8	Homedale Substation	2/29/08	2025	109,453
9	North River Operations Center	1/31/08	2019	2,630,412
10	Line #854 500 Kv	3/31/09	2024	308,066
11				
12				
13				
14	Column B and C if no date listed it is various			
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Boise Operations Center	12/31/82	2017	82,790
23	Transmission Stations			199,069
24	Distribution Stations			69,941
25	Homedale Substation	2/29/08	2025	217,797
26	Beacon Light Substation	12/30/02	2020	555,940
27	Underground Vault, Blaine County	8/30/16	2020	443,545
28				
29				
30				
31	Column B and C if no date listed it is various			
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			7,440,603

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	ROLLUP RELIC COST BROWNLEE	94,115,655
2	ROLLUP RELIC COST HELLS CANYON	64,130,776
3	GATEWAY WEST 500KV LINE	32,341,951
4	ROLLUP RELIC COST OXBOW	29,790,797
5	HELLS CANYON RELICENSING OUTSI	25,648,763
6	B2H PERMITTING 11/1/2011 & FOR	13,253,239
7	BOARDMAN - HEMINGWAY 500 KV LI	12,594,948
8	BROWNLEE UNIT 3 TURBINE REFURB	8,062,489
9	HCC WATERSHED ENHANCEMENT PROG	4,915,672
10	LEGAL DEPT. LABOR FOR RELICENS	3,960,343
11	BROWNLEE UNIT 2 TURBINE REFURB	3,807,724
12	BROWNLEE UNIT 4 TURBINE REFURB	3,645,624
13	BAYHA ISLAND RESEARCH PROJECT	3,537,551
14	RAPID RIVER HATCHERY INTAKE SC	3,221,312
15	REL-HCC OREGON REAUTHORIZATION	3,000,969
16	WQ HCC401 CERTIFICATION OPS AN	2,942,538
17	B2H TLINE CONSTRUCTION COSTS	2,687,809
18	OUTAGE MANAGEMENT SYSTEM (OMS)	2,143,924
19	700MHZ SPECTRUM PURCHASE	2,113,759
20	WDRI-KCHM NEW 138KV	1,959,756
21	WQ HCC401 APPLICATION, REVISIO	1,860,230
22	HCC MOONSHINE MINE DEEP WATER	1,851,957
23	FALL CHINOOK PROGRAM - REDD SU	1,705,552
24	BULL TROUT PROGRAM - ADMINISTR	1,679,070
25	BRIDGER UNDISTRIBUTED WORK ORD	1,627,000
26	BOBN140003 - REPL 138KV BUS PR	1,622,364
27	METEOROLOGY MODEL FOR OPERATIO	1,621,407
28	HBND-041:ALT LINE ROUTE TO GAR	1,599,669
29	RELICENSING: BAKER COUNTY SETT	1,579,612
30	BLISS UNIT 3 TURBINE REBURBISH	1,529,927
31	BRIDGER 2016C052 U2 REPLACE FI	1,472,497
32	T4331001-2017 KING TO WOOD RIV	1,438,150
33	REC - BAKER COUNTY SETTLEMENT	1,402,585
34	CR&B ENHANCEMENT & SUPPORT PAC	1,363,584
35	HC EVALUATION OF MAINSTEM SEDI	1,281,365
36	BLISS UNIT 3 GENERATOR REWIND	1,262,344
37	HCC RELICENSING WATER QUALITY	1,199,403
38	GRAND VIEW IRRIGATION UPGRADE	1,101,079
39	Other Minor Projects Under 1,000,000	59,995,130
40		
41		
42		
43	TOTAL	405,068,524

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 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), 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.

Section A. Balances and Changes During Year

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)
1	Balance Beginning of Year	2,071,784,276	2,071,784,276		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	135,048,584	135,048,584		
4	(403.1) Depreciation Expense for Asset Retirement Costs	720,272	720,272		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,983,339	3,983,339		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	102,213	102,213		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	139,854,408	139,854,408		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	50,773,113	50,773,113		
13	Cost of Removal	15,807,186	15,807,186		
14	Salvage (Credit)	2,333,822	2,333,822		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	64,246,477	64,246,477		
16	Other Debit or Cr. Items (Describe, details in footnote):	3,357,063	3,357,063		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,150,749,270	2,150,749,270		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	554,543,068	554,543,068		
21	Nuclear Production				
22	Hydraulic Production-Conventional	413,700,238	413,700,238		
23	Hydraulic Production-Pumped Storage				
24	Other Production	105,528,829	105,528,829		
25	Transmission	350,571,312	350,571,312		
26	Distribution	610,936,319	610,936,319		
27	Regional Transmission and Market Operation				
28	General	115,469,504	115,469,504		
29	TOTAL (Enter Total of lines 20 thru 28)	2,150,749,270	2,150,749,270		

Schedule Page: 219 Line No.: 16 Column: c

CIAC, Reserve Adjustments and Asset Retirement Obligation activity.

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under 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.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Idaho Energy Resources Company			
2	Common Stock	02/01/74		500
3	Capital contributions			2,462,594
4	Equity in earnings			81,674,307
5				
6	Subtotal Idaho Energy Resources Company			84,137,401
7				
8				
9				
10				
11				
12				
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19				
20				
21				
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36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	84,137,401

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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 form investments, including such revenues form 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 difference 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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		500		2
		2,462,594		3
7,993,526	15,000,000	74,667,833		4
				5
7,993,526	15,000,000	77,130,927		6
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				41
7,993,526	15,000,000	77,130,927		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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)	61,818,257	53,700,442	Electric
2	Fuel Stock Expenses Undistributed (Account 152)		-2,623	Electric
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)	17,384,869	17,442,341	
8	Transmission Plant (Estimated)	11,191,094	13,353,307	
9	Distribution Plant (Estimated)	21,957,543	21,236,284	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,911,722	2,422,752	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	52,445,228	54,454,684	Electric
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	4,478,320	3,403,797	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	118,741,805	111,556,300	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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	BPAP Network SIS 83177020	5,995	186623	(10,000)	186623
3					
4					
5					
6					
7					
8					
9					
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11					
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19					
20					
21	**Generation Studies**				
22	MAHLHUER RIVER SOLAR #477		186623		186623
23	LITTLE VALLEY SOLAR 491		186623	7,859	186623
24	BAKER SOLAR 1 #507	207	186623	(253)	186623
25	BAKER SOLAR 2 #508	44	186623	(91)	186623
26	BOISE CITY SOLAR #432	(5,354)	186623	72,705	186623
27	DAVIS SOLAR # 506	44	186623	(146)	186623
28	EVERGREEN SOLAR #475		186623	35,943	186623
29	FAIRWAY SOLAR #493		186623	7,332	186623
30	HUNTINGTON SOLAR 1 #505	801	186623	(755)	186623
31	JACKPOT SOLAR NORTH #502	25,418	186623	(33,392)	186623
32	JACKPOT SOLAR SOUTH #503	21,032	186623	(33,577)	186623
33	JOHN DAY SOLAR #480	1,189	186623	38,314	186623
34	MAHLHUER RIVER SOLAR #477		186623	26,913	186623
35	MERIDIAN/NORTH RD PV1-A	1,890	186623	7,670	186623
36	MOORES HOLLOW #476		186623	36,371	186623
37	MORTH GOODING MAIN HYDRO #494	2,369	186623	19,212	186623
38	MOUTAIN HOME SOLAR-20MW #435	2,346	186623	16,286	186623
39	OLD FERRY ROAD SOLAR #473	408	186623	35,130	186623
40	ONTARIO SOLAR #504	1,843	186623	(1,856)	186623

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

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					
3					
4					
5					
6					
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21	**Generation Studies**				
22	ORCHARD RANCH 2 #488		186623	10,000	186623
23	ORCHARD RANCH SOLAR-20MW #441	327	186623	16,447	186623
24	POCATELLO SOLAR-20MW #436		186623	18,811	186623
25	SIMCOE SOLAR 2 # 487		186623	42,808	186623
26	SIMCOE SOLAR CENTER #428	840	186623	12,281	186623
27	SOUTHERN IDAHO SOLID WASTE #501	6,809	186623	(26,021)	186623
28	SUTTON CREEK SOLAR #495	2,488	186623	6,384	186623
29	WEGNER SOLAR #499		186623	671	186623
30	BAKER CITY 1 SOLAR		186623	(10,000)	186623
31	BRUSH SOLAR #512	7,374	186623	(34,115)	186623
32	CARTER SOLAR #517	11,268	186623	(10,000)	186623
33	IPCO COMMUNITY SOLAR #509		186623		186623
34	JACKPOT SOLAR EAST #514	17,114	186623	(45,000)	186623
35	JACKPOT SOLAR WEST #513	17,007	186623	(45,000)	186623
36	MORGAN SOLAR #510	8,575	186623	(38,575)	186623
37	SHOSHONE FALLS HYDRO PROJECT IPCO	2,149	186623		186623
38	VALE 1 SOLAR #511	5,549	186623	(31,944)	186623
39					
40					

Schedule Page: 231 Line No.: 2 Column: d

Amounts in column D represent both reimbursements received (credit amounts) and refunds back to the counterparties (debit amounts). Refunds are initiated when the initial deposit exceeds the final expenses.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During the Quarter /Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Fixed Cost Adjustment (FCA) (182302)	27,938,848	34,892,466	400, 1823	27,963,827	34,867,487
2	Order #33527 (Amort period 06/17 thru 05/18)					
3						
4	AOCI Impact of Unfunded Post Retirement Liability	(1,524,416)	1,599,868	2283	26,083	49,369
5	Order #30256 (182306)					
6						
7	FCA Calender Mo Adjustment	1,056,775	5,786,559	400	10,236,716	-3,393,382
8	Order #33295 (182308)					
9						
10	Prior Year FCA - Order #33527 (182309)	7,824,769	28,054,542	400	22,908,285	12,971,026
11	(Amort period 06/16 thru 05/17)					
12						
13	PCA Unbilled Amortization (182316)	(1,210,063)	3,950,415	400/401	4,727,806	-1,987,454
14	(Amort period 06/16 thru 05/17)					
15						
16	AOCI Impact of Unfunded Pension Liability	253,286,229	23,833,252	2283	13,389,529	263,729,952
17	Order #30256 (182320)					
18						
19	Deferred Pension Expense Net of Contributions	21,204,591	40,088,330	Various	38,997,492	22,295,429
20	Order #30333 (182321)					
21						
22	FAS 109 Unfunded (182322)	875,027,482	73,512,340			948,539,822
23	Accum Deferred Income Noncurrent					
24						
25	PCA Deferral Idaho - Order #33526	49,340,227	64,650,399	Various	61,001,484	52,989,142
26	(Amort period 06/17 thru 05/18) (182323)					
27						
28	PCA Prior Year Deferral Idaho - Order #33526	2,749	43,860,736	Various	33,709,156	10,154,329
29	(Amort period 06/16 thru 05/17) (182324)					
30						
31	PCA Unbilled Forecast - Order #32821 (182325)	(2,117,153)	6,257,162	401	7,167,419	-3,027,410
32						
33	PCA SBA Unbilled Adj-Order #33307 (182326)	(1,459,348)	8,427,488	401	11,653,921	-4,685,781
34						
35	Idaho Pension Cash - Order #32248 (182327)	61,318,926	38,891,706	401	17,153,713	83,056,919
36	(Amort period beginning 06/11 thru indefinite)					
37						
38	PCAM Interest Reserve 2008 (182329)	(330,493)	254,983			-75,510
39	(Amort period 01/14 - 06/17)					
40						
41	ASC 815 Mark to Market (182330 & 182333)	4,972,600	8,557,502	244	13,530,102	
42	Order #28661					
43						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During the Quarter /Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Oregon Pension Expense Capitalized (182339)	3,266,661	597,030	401, 4073	106,917	3,756,774
2	Order #10-064					
3						
4	Asset Retirement Obligations (182341)	14,180,771	1,285,929	230	1,495,854	13,970,846
5	IPUC Order #29414-OPUC Order #04-585					
6						
7	PCAM Oregon 2008 (182346)	3,231,443	57,012	401	2,548,989	739,466
8	Order #08-238 & #13-439 (Amort 01/14 - 06/17)					
9						
10	OATT Deferral - Order #33313 (182350)	1,083,701	3,332,340	400/4210	4,416,041	
11						
12	2008 PCAM Unbilled Amort (182356)	(165,472)	410,612	401	440,333	-195,193
13	(Amort period 01/14 thru 06/17)					
14						
15	Lidar Surveys - Order #32426 (182361)	261,628		402	43,605	218,023
16	(Amort period 01/12 thru 12/21)					
17						
18	PS&I Shoshone - Order #29904 (182368)	666,978		401	266,791	400,187
19	(Amort period 07/15 thru 06/18)					
20						
21	Oregon CUB Fund Amortization-Order 15-399 (182386)	272,714		401	192,504	80,210
22	(Amort period 01/16 thru 05/17)					
23						
24	Idaho Boardman ARO - Order #29414 (182393)	217,783		4031, 4110	43,557	174,226
25	(Amort period thru 2020)					
26						
27	Langley Revenue Accrual - Order #12-226 (182398)	1,017,428	81,518			1,098,946
28						
29	Siemens Long Term Deferred Rate Base (182410)	11,632,907		4073	431,488	11,201,419
30	Order #33420 (Amort period 01/16 thru 12/42)					
31						
32	Siemens Long Term Deferred Rate Base (182411)	17,358,636		4073	643,866	16,714,770
33	Order #33420 (Amort period 01/16 thru 12/42)					
34						
35	Siemens Long Term Deferred Rate Base (182412)	446,876	34,485	Various	39,587	441,774
36	Order #15-387 (Amort period 01/16 thru 12/42)					
37						
38	Siemens Long Term Deferred Rate Base (182413)	786,315		4073	29,166	757,149
39	Order #15-387 (Amort period 01/16 thru 12/42)					
40						
41	Idaho Boardman Decomissioning (182493)	1,413,643	5,501,115	Various	5,443,473	1,471,285
42	Order #32549 & #32457					
43						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During the Quarter /Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Oregon DSM Rider (182405)	4,482,485	2,748,208	Various	1,678,552	5,552,141
2	Advise #05-03					
3						
4	Minor Items (21)	85,908	334,223	Various	345,691	74,440
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44	**TOTAL :**	1,355,572,128	397,000,220		280,631,947	1,471,940,401

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Prepaid Credit Facility(186025)	1,044,482	1,170,936	Various	1,192,172	1,023,246
2	(Amort period 11/16 thru 11/20)					
3						
4	Prepaid Service Contract	753,844	2,078,867	165, 401	644,515	2,188,196
5	Long Term Portion (186052)					
6						
7	Long Term (186121)	1,069,659		401, 222	27,782	1,041,877
8	Workers Compensation					
9						
10	Prepaid ROW (186160)	382,974		401	43,087	339,887
11	Rents/Easements Long Term					
12						
13	Long-Term Portfolio (186255)	1,093,626		165, 402	628,157	465,469
14						
15	OATT Reserve (186350)	-1,083,701	4,416,041	400,4210	3,332,340	
16						
17	Advance Prepaid (186709)	1,170,132		151	81,692	1,088,440
18	Coal Royalties					
19						
20	Stable Value Life (186719)	30,004,992	11,452,706	186	35,089	41,422,609
21						
22	Security Plan (186720)	14,769,993	250,078	143,4262	2,643,498	12,376,573
23	Net Insurance Asset					
24						
25	American Falls Bond Ref(186722)	133,395		401	14,552	118,843
26	(Amort Period 04/00 thru 02/25)					
27						
28	Retiree Medical-COLI (186726)	3,791,248	731,351	143,4262	768,623	3,753,976
29						
30	American Falls Water Rights	9,464,913		401	1,042,009	8,422,904
31	(Amort 01/06 - 02/25) (186727)					
32						
33	Shelf Registration (186733)		147,328	186		147,328
34						
35	Milner Bond Guarantee (186734)	2,127,273		253	1,063,637	1,063,636
36	(Amort 02/07 - 2/17)					
37						
38	American Falls - Bond Refinance	439,992		401	47,999	391,993
39	(Amort through 02/25) (186770)					
40						
41	Power Plant - Bridger (186780)	127,397		401	127,397	
42	(Amort thru 06/14 thru 12/16)					
43						
44	Bridger Coal Study (186781)	1,405,787	66,827	107	355	1,472,259
45						
46	Minor Items (3)	5,289	1,683,166	Various	1,673,034	15,421
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	66,701,295				75,332,657

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 of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2			
3			
4			
5	Other Electric (See footnote)	83,181,338	92,773,039
6			
7	Other (See footnote)	163,213,808	168,030,701
8	TOTAL Electric (Enter Total of lines 2 thru 7)	246,395,146	260,803,740
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other Non Electric See footnote	23,793,249	25,522,789
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	270,188,395	286,326,529

Notes

Schedule Page: 234 Line No.: 5 Column: c

	Beginning Balance	Ending Balance
Prov for Rate Refund-HC Relicensing (AFUDC)	34,282,231	40,353,531
Deferred Idaho ITC	19,624,338	21,721,941
VEBA-Post Retirement Benefits	11,343,166	11,747,529
Incentive Deferral-Profit Sharing-Not in Rates	3,814,372	4,939,496
Stock Based Compensation	3,813,934	3,861,627
Revenue Sharing	1,235,198	0
Pension Expense-Oregon	3,008,600	3,523,081
Rate Case Disallowance	2,273,741	2,157,902
Construction Advances	1,637,625	1,838,458
Asset Retirement Obligation (ARO)	1,171,048	1,543,332
Postretirement Benefits	486,873	566,112
Bridger Revenue Deferral	316,603	442,426
Executive Deferred Compensation	39,761	39,761
Retention Pay Accrual	0	22,212
Deferred GBC Federal	31,500	69,872
USBR-American Falls O&M Costs Settlement	138,920	125,256
Non-VEBA Pension and Benefits	(36,572)	(179,497)
Total Other Electric	83,181,338	92,773,039

Schedule Page: 234 Line No.: 7 Column: c

	Beginning Balance	Ending Balance
Pension-FAS 158	99,022,251	103,332,880
Regulatory Liability-FAS 109	51,130,605	51,326,330
Minimum Pension Liability	13,656,923	13,403,940
Postretirement Plan-FAS 158	(595,971)	(32,449)
Total Other	163,213,808	168,030,701

Schedule Page: 234 Line No.: 17 Column: c

	Beginning Balance	Ending Balance
Senior Management Security Plan	23,635,408	25,522,789
Micron CIAC-Depr Timing Diff	153,366	0
Meridian Gold CIAC-Depr Timing Diff	4,475	0
Total Non Electric	23,793,249	25,522,789

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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.

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)
1	Account 201			
2	Common Stock all of which is held by	50,000,000	2.50	
3	IdaCorp, Inc. and not traded			
4	Total Common Stock	50,000,000	2.50	
5				
6	Account 204 - None			
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CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (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 non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
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 purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
39,150,812	97,877,030					2
						3
39,150,812	97,877,030					4
						5
						6
						7
						8
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						10
						11
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

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 total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. 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 give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on 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 which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 208 - Donations received from stockholders - None	
2		
3	Account 209 - Reduction in par or stated value of Capital Stock - None	
4		
5	Account 210 - Gain on reacquired Capital Stock - None	
6		
7		
8	Account 211 - Miscellaneous paid-in Capital - None	
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39		
40	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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
2		
3		
4		
5		
6		
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10	Explanation of Changes during the year:	
11		
12		
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22	TOTAL	2,096,925

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

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

1. Report by balance sheet account the particulars (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. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. 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.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221:		
2	First Mortgage Bonds:		
3	4.50% Series due 2020	130,000,000	1,190,698
4			234,601 D
5			
6	5.50% Series due 2033	70,000,000	728,701
7			36,400 D
8			
9	6.15% Series Due 2019	100,000,000	1,034,909
10			184,949 D
11			
12	3.40% Series due 2020	100,000,000	1,159,871
13			498,864 D
14			
15	5.30% Series Due 2035	60,000,000	408,411 D
16			3,802,019
17			
18	4.00% Series due 2043	75,000,000	742,017
19			193,836 D
20			
21	6.00% Series due 2032	100,000,000	1,191,216
22			543,244 D
23			
24	5.875% Series due 2034	55,000,000	-585,759
25			746,961 D
26			
27	5.50% Series due 2034	50,000,000	524,419
28			383,322 D
29			
30	4.85% Series Due 2040	100,000,000	1,284,871
31			169,984 D
32			
33	TOTAL	1,877,045,000	31,172,757

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, 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) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
11/20/09	3/1/20	11/20/09	3/1/20	130,000,000	5,850,000	3
						4
						5
05/01/03	04/01/33	05/01/03	03/31/33	70,000,000	3,850,000	6
						7
						8
4/1/09	4/1/19	4/1/09	4/1/19		1,708,333	9
						10
						11
11/1/10	5/1/2020	11/1/10	5/1/20	100,000,000	3,400,000	12
						13
						14
08/26/05	08/26/35	08/26/05	08/26/35	60,000,000	3,180,000	15
						16
						17
4/8/2013	4/1/2043	4/8/2013	4/1/2043	75,000,000	3,000,000	18
						19
						20
11/15/02	11/15/32	11/15/02	11/15/32	100,000,000	6,000,000	21
						22
						23
08/16/04	08/16/34	08/16/04	08/16/34	55,000,000	3,231,250	24
						25
						26
03/26/04	03/15/34	03/26/04	03/15/34	50,000,000	2,750,000	27
						28
						29
2/15/10	8/15/40	2/15/10	8/15/40	100,000,000	4,850,000	30
						31
						32
				1,766,408,636	81,956,468	33

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

1. Report by balance sheet account the particulars (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. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. 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.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	6.30% Series due 2037	140,000,000	1,495,799
2			278,367 D
3			
4	6.25% Series due 2037	100,000,000	1,141,489
5			267,677 D
6			
7	Port of Morrow Variable due 2027	4,360,000	188,545
8			
9	Humboldt Variable due 2024	49,800,000	1,697,856
10			
11	Sweetwater Variable due 2026	116,300,000	3,026,122
12			
13	2.50% Series due 2023	75,000,000	648,267
14			371,854 D
15			
16	4.30% Series Due 2042	75,000,000	802,240
17			49,417 D
18			
19	2.95% Series Due 2022	75,000,000	708,490
20			127,607 D
21			
22	3.65% Series Due 2045	250,000,000	2,559,510
23			1,715,000 D
24			
25	4.05% Series Due 2046	120,000,000	1,311,383
26			309,600 D
27			
28	Subtotal Account 221	1,845,460,000	31,172,757
29			
30	Account 222 - Reaquired Bonds		
31			
32	Account 223: Advances for Associated Companies		
33	TOTAL	1,877,045,000	31,172,757

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, 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) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
6/22/07	6/15/2037	6/22/07	6/15/37	140,000,000	8,820,000	1
						2
						3
10/18/07	10/15/2037	10/18/07	10/15/37	100,000,000	6,250,000	4
						5
						6
05/17/00	02/01/27	05/17/00	02/01/27	4,360,000	30,435	7
						8
10/22/03	12/01/24	11/01/03	12/01/24	49,800,000	2,564,700	9
						10
10/3/06	7/15/26	10/3/06	7/15/26	116,300,000	6,105,750	11
						12
4/8/2013	4/1/2023	4/8/2013	4/1/2023	75,000,000	1,875,000	13
						14
						15
4/13/12	4/1/42	4/13/12	4/1/42	75,000,000	3,225,000	16
						17
						18
4/13/12	4/1/22	4/13/12	4/1/22	75,000,000	2,212,500	19
						20
						21
3/6/15	3/1/45	3/6/15	3/1/45	250,000,000	9,125,000	22
						23
						24
3/10/16	3/1/46	3/10/16	3/1/46	120,000,000	3,928,500	25
						26
						27
				1,745,460,000	81,956,468	28
						29
						30
						31
						32
				1,766,408,636	81,956,468	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

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

1. Report by balance sheet account the particulars (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. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
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6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	Account 224:		
3	Bond Guarantee - American Falls	19,885,000	
4	Note Guarantee - Milner Dam	11,700,000	
5	Subtotal Account 224	31,585,000	
6			
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32			
33	TOTAL	1,877,045,000	31,172,757

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, 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) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
04/26/00	2/1/25			19,885,000		3
02/10/92				1,063,636		4
				20,948,636		5
						6
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						32
				1,766,408,636	81,956,468	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	189,241,920
2		
3		
4	Taxable Income Not Reported on Books	
5		9,120,278
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		-19,264,218
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		28,771,306
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		151,969,063
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-1,642,387
28	Show Computation of Tax:	
29	Tenative Federal Tax @ 35%	-574,835
30		
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Schedule Page: 261 Line No.: 5 Column: b

4005-AVOIDED COST	5,713,081
4003-CONSTRUCTION ADVANCES	573,808
4013-CIAC - TAXABLE - ACCT 107	1,343,114
4021-ENGINEERING FEES - TAXABLE - ACCT 107	175,222
4024-RENEWABLE ENERGY CERTIFICATES (REC) SALES	1,718,789
4506-MERIDIAN GOLD CIAC - DEPR TIMING DIFF - NON-OP	(11,446)
4507-MICRON CIAC - DEPR TIMING DIFF - NON-OP	(392,290)
Total	**9,120,278**

Schedule Page: 261 Line No.: 10 Column: b

Total Federal and State taxes deducted on books	**34,302,445**
5001-BAD DEBT EXPENSE	(223,283)
5022-263A CAPITALIZED OVERHEADS	(30,000,000)
5024-NON-DEDUCTIBLE MEALS	500,000
5070-INCENTIVE DEFERRAL-CRI & RELIABILITY-INCLUDED IN RATES	3,406,871
5010-POSTEMPLOYMENT BENEFITS	202,685
5023-PENSION EXPENSE	(22,846,287)
5035-PCA EXPENSE DEFERRAL	(8,886,414)
5047-EXECUTIVE DEFERRED COMP	0
5053-STOCK BASED COMPENSATION	121,992
5058-FIXED COST ADJUSTMENT	(7,624,739)
5060-OREGON - PCAM	2,266,716
5061-PENSION EXPENSE - OREGON	1,315,976
5065-VALMY UNION PACIFIC CONTRACT	0
5067-ASSET RETIREMENT OBLIGATION (ARO)	952,255
5069-M & E RESERVE	0
5071-INCENTIVE DEFERRAL-PROFIT SHARING-NOT IN RATES	2,877,922
5501-SMSP - INSURANCE COSTS	(1,539,906)
5503-EDC - UNREALIZED GAIN/LOSS FROM RABBI TRUST	0
5504-NON-DEDUCTIBLE POLITICAL EXPENSES	1,081,872
5505-SMSP - NET	4,827,677
Total Line 10	**(19,264,218)**

Schedule Page: 261 Line No.: 15 Column: b

7501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES	7,993,526
7509-SMSP - INSURANCE PROCEEDS	923,666
7502-ALLOWANCE FOR OFUDC	22,030,622
7503-ALLOWANCE FOR BFUDC	10,193,622
7010-PROV FOR RATE REFUND - HC RELICENSING (AFUDC)	(15,529,608)
7011-OATT REVENUE DEFICIENCY	0
7012-REVENUE SHARING	3,159,478
7013-LANGLEY REVENUE ACCRUAL	0
Total Line 15	**28,771,306**

Schedule Page: 261 Line No.: 20 Column: b

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5538-STOCK BASED COMP - STOCK	3,905,006
8702-STOCK BASED COMP - DIVIDENDS	618,377
8025-MANUFACTURING DEDUCTION	0
8034-REMOVAL COSTS	15,883,233
8042-GAIN/LOSS ON REACQUIRED DEBT	12,244,496
8073-REPAIRS DEDUCTION	80,000,000
8077-PREPAID INSURANCE & OTHER EXPENSES	(202,826)
8001-VEBA - POST RETIREMENT BENEFITS	(1,047,703)
8020-CONSERVATION EXPENSES	1,053,843
8059-SOFTWARE - LABOR COSTS DEDUCTED - ACCT 107	1,900,000
8072-RELICENSING - LABOR COSTS DEDUCTED - ACCT 107	2,200,000
8009-DEPR TIMING DIFF - OPERATING - FEDERAL	30,911,318
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN	4,503,319
Total	**151,969,063**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

TAXES ACCRUED, PREPAID AND CHARGED 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 know, 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 (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) 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.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	Income	-5,185,372		464,352	15,218,447	
3	Social Security - (FOAB)	-534		15,391,446	14,949,530	-533
4	Unemployment			132,993	95,131	
5	Subtotal Federal	-5,185,906		15,988,791	30,263,108	-533
6						
7	State of Idaho:					
8	Property	9,435,081		22,108,882	21,948,161	
9	Non-Operating	10,346		26,542	27,291	
10	Income	-258,247		3,717,211	6,573,864	
11	KWH	92,925		1,405,449	1,420,374	
12	Unemployment			566,515	542,928	
13	Regulatory Commission			2,212,657	2,212,657	
14	Business License - Sho Ban			150	150	
15	Subtotal Idaho	9,280,105		30,037,406	32,725,425	
16						
17	State of Oregon					
18	Property		1,596,798	3,189,676	3,184,038	
19	Non-Operating Property		948	1,921	1,946	
20	Income	-106,776		67,740	209,442	
21	Regulatory Commission			224,995	224,995	
22	Unemployment	-857		54,996	51,227	
23	Franchise	197,487		820,300	823,375	
24	Subtotal Oregon	89,854	1,597,746	4,359,628	4,495,023	
25						
26	State of Montana:					
27	Property	169,627		322,249	330,789	
28	Subtotal Montana	169,627		322,249	330,789	
29						
30	State of Nevada:					
31	Property		536,309	1,035,811	987,024	
32	Subtotal Nevada		536,309	1,035,811	987,024	
33						
34	State of Wyoming					
35	Corporate License			4,680	4,680	
36	Property	815,142		1,593,455	1,611,869	
37	Subtotal Wyoming	815,142		1,598,135	1,616,549	
38						
39						
40						
41	TOTAL	5,192,418	2,134,055	37,183,591	70,415,420	1,537

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) 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 (i) through (l) how the taxes were distributed. Report in column (I) 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 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) 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.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-19,939,467		-96,137			560,489	2
441,915		15,391,446				3
37,862		132,993				4
-19,459,690		15,428,302			560,489	5
						6
						7
9,595,802		22,107,982			900	8
9,597					26,542	9
-3,114,901		3,617,124			100,087	10
78,001		1,405,449				11
23,588		566,515				12
		2,212,657				13
		150				14
6,592,087		29,909,877			127,529	15
						16
						17
	1,591,160	3,089,583			100,093	18
					1,921	19
-248,478		62,813			4,927	20
	973	224,995				21
2,912		54,996				22
194,412		820,300				23
-51,154	1,592,133	4,252,687			106,941	24
						25
						26
161,088		322,249				27
161,088		322,249				28
						29
						30
	487,522	1,035,811				31
	487,522	1,035,811				32
						33
						34
		4,680				35
796,727		1,593,455				36
796,727		1,598,135				37
						38
						39
						40
-11,945,257	2,079,655	36,386,454			797,137	41

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

TAXES ACCRUED, PREPAID AND CHARGED 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 know, 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 (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) 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.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	State of Washington					
2	Property			6,000		
3	Subtotal Washington			6,000		
4						
5	Other States Income	31,516		-18,479	3,314	
6	Payroll Tax Credit			-16,145,950		
7	Canada GST tax	-7,920			-5,812	2,070
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
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31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	5,192,418	2,134,055	37,183,591	70,415,420	1,537

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) 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 (i) through (l) how the taxes were distributed. Report in column (I) 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 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) 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.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
6,000		6,000				2
6,000		6,000				3
						4
9,723		-20,657			2,178	5
		-16,145,950				6
-38						7
						8
						9
						10
						11
						12
						13
						14
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						40
-11,945,257	2,079,655	36,386,454			797,137	41

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Schedule Page: 262 Line No.: 2 Column: l

Account 409.2 $ 560,489

Schedule Page: 262 Line No.: 3 Column: f

FICA Refund is an adjustment because the offset account is not a 600 expense account.

Schedule Page: 262 Line No.: 8 Column: l

Account 107 $ 900

Schedule Page: 262 Line No.: 9 Column: l

Account 408.2 $ 26,542

Schedule Page: 262 Line No.: 10 Column: l

Account 409.2 $ 100,087

Schedule Page: 262 Line No.: 18 Column: l

Account 107 $ 100,093

Schedule Page: 262 Line No.: 19 Column: l

Account 408.2 $ 1,921

Schedule Page: 262 Line No.: 20 Column: l

Account 409.2 $ 4,927

Schedule Page: 262.1 Line No.: 5 Column: l

Account 409.2 $ 2,178

Schedule Page: 262.1 Line No.: 6 Column: i

This amount is an offset to lines 3, 4, 12 and 22. Each month employer paid taxes flow into various 408.1 accounts. In that same month these amounts are offset with a different 408.1 account. These payroll taxes are then allocated back to the balance sheet and O&M accounts based on current month labor charges.

Schedule Page: 262.1 Line No.: 7 Column: f

Canada GST accrual is an adjustment because the offset account is not a 600 expense account.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/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 Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	377,771				53,844	
4	7%						
5	10%	18,316,035				1,374,923	
6	11%	1,135,795				26,029	
7	Other- State	59,825,329	411.4	3,227,080	411.4	1,467,369	
8	TOTAL	79,654,930		3,227,080		2,922,165	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 Col A 11%						
11							
12	State of Idaho	59,825,329	411.4	3,227,080	411.4	1,467,369	
13							
14							
15							
16							
17							
18							
19							
20							
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
323,927	7.02		3
			4
16,941,112	13.32		5
1,109,766	43.64		6
61,585,040	40.77		7
79,959,845			8
			9
			10
			11
61,585,040			12
			13
			14
			15
			16
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OTHER DEFFERED 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 Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Point to Point Trans Study(253201)	2,058,725	235	211,500		1,847,225
2						
3	FTV (253202)	2,466,666	400	400,000		2,066,666
4	(Amort Period Mar 1998-Feb 2023)					
5						
6	Sho Ban Trans ROW (253480)	187,500	242	15,000		172,500
7	(Amort Period Jan 2005-Dec 2027)					
8						
9	Operations Accrual (253550)	1,293,253	Various	1,035,594	266,797	524,456
10						
11	Milner Falling Water (253953)	713,831	186	1,063,636	1,205,477	855,672
12	Amort Period (Feb 1992 - Feb 2017)					
13						
14	Postretirement Benefits (253960)	1,245,358	253	1,245,358	1,448,043	1,448,043
15						
16	Directors Deferred Compensation	3,789,347	131	525,032	296,354	3,560,669
17	(253980-253999)					
18						
19	Minor Items (1) 253042	3,318	401	74,236	75,029	4,111
20						
21						
22						
23						
24						
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41						
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43						
44						
45						
46						
47	TOTAL	11,757,998		4,570,356	3,291,700	10,479,342

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

ACCUMULATED DEFFERED 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	469,103,751	39,050,389	12,942,903
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	469,103,751	39,050,389	12,942,903
6	Non-Operating Property			
7	Other - Regulatory Asset	875,027,483		
8	Like Kind Exchange- Reclass No	5,775,786		
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,349,907,020	39,050,389	12,942,903
10	Classification of TOTAL			
11	Federal Income Tax	1,156,602,661	38,712,647	12,834,476
12	State Income Tax	193,304,359	337,742	108,427
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
			-144,665			495,355,902	2
							3
							4
			-144,665			495,355,902	5
							6
				182	73,512,341	948,539,824	7
		282100	144,665			5,631,121	8
					73,512,341	1,449,526,847	9
							10
					60,909,109	1,243,389,941	11
					12,603,232	206,136,906	12
							13

NOTES (Continued)

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Schedule Page: 274 Line No.: 2 Column: b

Account	2016 Beginning Balance	Changes during Year DR to 410.1	CR to 411.1	Adjustments Debits Acct. credited	Amount	Adjustments Credits Acct. debited	Amount	2016 Ending Balance
Depreciation Timing Diff-Operating	453,391,724	38,856,279	12,310,946			Trf	5,775,786	485,712,843
Like Kind Exchange - Reclass Non-Rate Base	-			282111	(144,665)	Trf	(5,775,786)	(5,631,121)
Intangible-Labor Costs Deducted-Acct 107	18,348,619	(648,922)						17,699,697
CIAC-Taxable-Acct 107	(3,287,799)	366,430	470,090					(3,391,459)
Valmy Capitalized Items	63,560		63,560					-
Software-Labor Costs Deducted-Acct 107	1,051,482	476,602						1,528,084
Engineering Fees-Taxable-Acct 107	(463,835)	-	98,307					(562,142)
TOTAL Line 2	469,103,751	39,050,389	12,942,903		(144,665)		-	495,355,902

ACCUMULATED DEFFERED 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Other Electric -- See Note	64,162,105	17,030,507	1,636,552
4				
5				
6				
7				
8	Other -- See Note	98,426,282		
9	TOTAL Electric (Total of lines 3 thru 8)	162,588,387	17,030,507	1,636,552
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	318,236		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	162,906,623	17,030,507	1,636,552
20	Classification of TOTAL			
21	Federal Income Tax	136,654,884	14,286,110	1,372,828
22	State Income Tax	26,251,739	2,744,397	263,724
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						79,556,060	3
							4
							5
							6
							7
					4,874,150	103,300,432	8
					4,874,150	182,856,492	9
							10
							11
							12
							13
							14
							15
							16
							17
6,221	419,715					-95,258	18
6,221	419,715				4,874,150	182,761,234	19
							20
5,219	352,080				4,088,701	153,310,006	21
1,002	67,635				785,449	29,451,228	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 3 Column: b

Account	2016 Beginning Balance	Changes during Year DR to 410.1	Changes during Year CR to 411.1	2016 Ending Balance
Pension Expense	27,664,003	9,118,756		36,782,759
PCA Expense	17,419,329	3,474,144		20,893,473
Conservation Expenses	1,733,392	412,000		2,145,392
Fixed Cost Adjustment	14,394,933	2,980,892		17,375,825
Oregon PCAM	1,131,323	2,803	886,173	247,953
Boardman Decommission	484,201	70,496		554,697
Oregon Excess Power Costs	(61,888)		2,803	(64,691)
PS & I Costs	-	260,755		260,755
Renewable Energy Certificates (REC) Sales	745,859		693,226	52,633
Langley Revenue Accrual	370,974			370,974
Royalty Income	-	361,616		361,616
2011 LIDAR Surveys Deferral	119,331		17,047	102,284
Bennett Mtn Maint Deferral	29,277		29,277	-
Intervenor Funding Orders	121,344	39,094		160,438
OPUC Grid West Loans	925		925	-
Emission Allowances	9,102		7,101	2,001
Siemens LTP Contract	-	37,092		37,092
Prepaid Credit Facility	(0)	272,859		272,859
TOTAL Line 3	64,162,105	17,030,507	1,636,552	79,556,060

Schedule Page: 276 Line No.: 8 Column: b

Account	2016 Beginning Balance	Adjustments Credits Acct. debited	Adjustments Credits Amount	2016 Ending Balance
Pension-FAS 158	99,022,252	190	4,310,629	103,332,881
Postretirement Plan-FAS 158	(595,970)	190	563,521	(32,449)
TOTAL Line 8	98,426,282		4,874,150	103,300,432

Schedule Page: 276 Line No.: 18 Column: b

Account	2016 Beginning Balance	DR to 410.2	CR to 411.2	2016 Ending Balance
EDC-Unrealized Gain/Loss From Rabbit Trust	4,420			4,420
SMSP-Unrealized Gain/Loss From Rabbi Trust	(41,951)		58,099	(100,050)
Royalty Income	355,408	6,208	361,616	0
Oregon Non-Op Prop Tax Adj	359	13		372
TOTAL Line 18	318,236	6,221	419,715	(95,258)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Market to Market Short Term - (254001)	278,759	175	5,863,292	13,415,950	7,831,417
2	IPUC Order #28661					
3						
4	Oregon Solar Pilot (254005)	3,040,517	Various	507,417	1,228,981	3,762,081
5	Order #10-198					
6						
7	Revenue Sharing (254101)	3,159,478	400, 1823	3,171,340	11,862	
8	IPUC Order #33149					
9						
10	Idaho DSM Rider (254201)	6,554,074	Various	43,278,699	47,454,776	10,730,151
11	IPUC Order #29026					
12						
13	FAS 133 Market to Market - (254203)	126,480	175	1,749,267	1,622,787	
14	IPUC Order #28661					
15						
16	BPA Credit Residential Idaho (254401)	2,025,068	Various	8,593,632	8,417,558	1,848,994
17	Advice # 15-13					
18						
19	Bridger Depreciation (254800)	1,131,669	400		319,767	1,451,436
20	OPUC Order #12-296					
21						
22	Unfunded Accum Def Income Tax (254966)	51,130,605	Various	525,024	720,749	51,326,330
23						
24	Minor Items (6)	265,005	Various	2,100,436	1,928,035	92,604
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	67,711,655		65,789,107	75,120,465	77,043,013

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	514,953,833	512,068,335
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	455,158,518	466,541,569
5	Large (or Ind.) (See Instr. 4)	182,590,036	182,254,287
6	(444) Public Street and Highway Lighting	3,996,825	4,039,381
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,156,699,212	1,164,903,572
11	(447) Sales for Resale	25,204,985	30,887,261
12	TOTAL Sales of Electricity	1,181,904,197	1,195,790,833
13	(Less) (449.1) Provision for Rate Refunds	10,706,040	13,865,518
14	TOTAL Revenues Net of Prov. for Refunds	1,171,198,157	1,181,925,315
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	4,089,617	4,119,479
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	14,260,349	24,852,979
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	34,259,879	31,174,302
22	(456.1) Revenues from Transmission of Electricity of Others	31,490,797	24,129,372
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	84,100,642	84,276,132
27	TOTAL Electric Operating Revenues	1,255,298,799	1,266,201,447

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ELECTRIC OPERATING REVENUES (Account 400)

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 pages 108-109, 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.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
5,004,352	4,977,176	440,362	432,275	2
				3
5,916,649	6,059,428	86,621	85,560	4
3,243,344	3,195,786	121	119	5
31,405	32,103	2,797	2,592	6
				7
				8
				9
14,195,750	14,264,493	529,901	520,546	10
1,185,879	1,254,136			11
15,381,629	15,518,629	529,901	520,546	12
				13
15,381,629	15,518,629	529,901	520,546	14

Line 12, column (b) includes $ 14,098,656 of unbilled revenues.

Line 12, column (d) includes 141,068 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 17 Column: b

This amount consists of:

Service Establishment/Connection Charges (Includes late and after hour charges)	$ 3,971,647
Misc. Under $250,000	117,970
Total Account 451	$ 4,089,617

Schedule Page: 300 Line No.: 21 Column: b

This amount consists of:

Alternate Distribution Service	$ 321,995
DSM Activity	33,754,060
Misc. Under $250,000	183,824
Total Account 456	$ 34,259,879

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. 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	440 - Residential Sales:					
2	01 - Residential	4,880,040	490,174,874	439,033	11,115	0.1004
3	03 - Residential Master Meter	3,842	368,532	22	174,636	0.0959
4	05 - Residential - TOD	21,216	2,061,824	1,307	16,233	0.0972
5	15 - Dusk to dawn lighting	2,631	647,151			0.2460
6	Unbilled Revenues	96,623	10,801,968			0.1118
7	Other Revenues		10,899,484			
8	Total 440	5,004,352	514,953,833	440,362	11,364	0.1029
9						
10	442-Commercial & Industrial Sales					
11	07 - General service	148,314	18,286,983	30,677	4,835	0.1233
12	09P - General service	483,647	31,260,864	217	2,228,788	0.0646
13	09S - General service	3,282,659	241,833,988	34,289	95,735	0.0737
14	09T - General service	6,052	431,147	4	1,513,000	0.0712
15	15 - Dusk to Dawn Light	4,216	747,696			0.1773
16	19P - Uniform rate contracts	2,224,994	128,490,778	114	19,517,491	0.0577
17	19S - Uniform rate contracts	6,363	404,552	1	6,363,000	0.0636
18	19T - Uniform rate contracts	130,478	7,484,540	3	43,492,667	0.0574
19	24S - Irrigation Pumping	1,948,079	155,460,562	20,535	94,866	0.0798
20	40 - General service	10,593	915,795	899	11,783	0.0865
21	Special Contracts	870,207	44,140,269	3	290,069,000	0.0507
22	Commercial & Industrial Unbill	44,391	3,287,794			0.0741
23	Other Revenues		5,003,586			
24	Total 442	9,159,993	637,748,554	86,742	105,600	0.0696
25						
26	444 - Public Street Lighting:					
27	40 - General service	857	74,365	459	1,867	0.0868
28	41 - Street lighting	27,737	3,712,785	1,768	15,688	0.1339
29	42 - Traffic control lighting	2,757	173,916	570	4,837	0.0631
30	Unbilled	54	8,894			0.1647
31	Other Revenues		26,865			
32	Total 444	31,405	3,996,825	2,797	11,228	0.1273
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	14,054,682	1,142,600,556	529,901	26,523	0.0813
42	Total Unbilled Rev.(See Instr. 6)	141,068	14,098,656	0	0	0.0999
43	TOTAL	14,195,750	1,156,699,212	529,901	26,789	0.0815

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 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	ADM Investor Services, Inc.	OS	-	n/a	n/a	n/a
2	Arizona Public Service Co.	SF	WSPP	n/a	n/a	n/a
3	Avangrid Renewables, LLC	SF	WSPP	n/a	n/a	n/a
4	Avangrid Renewables, LLC	OS	WSPP	n/a	n/a	n/a
5	Avangrid Renewables, LLC	OS	WSPP	n/a	n/a	n/a
6	Avista Corp.	SF	WSPP	n/a	n/a	n/a
7	Basin Electric Power Cooperative	SF	WSPP	n/a	n/a	n/a
8	Black Hills Power Inc.	SF	WSPP	n/a	n/a	n/a
9	Black Hills Power Inc.	OS	WSPP	n/a	n/a	n/a
10	Bonneville Power Administration	SF	WSPP	n/a	n/a	n/a
11	Calpine Energy Services, L.P.	SF	WSPP	n/a	n/a	n/a
12	Cargill Power Markets LLC	SF	WSPP	n/a	n/a	n/a
13	Citigroup Energy Inc.	SF	WSPP	n/a	n/a	n/a
14	Clatskanie PUD	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			1,405,428	1,405,428	1
179		7,295		7,295	2
4,728		113,488		113,488	3
			5,300	5,300	4
			5,949	5,949	5
96,781		1,501,183		1,501,183	6
2,160		11,465		11,465	7
3,679		28,930		28,930	8
			3	3	9
74,713		1,391,848		1,391,848	10
337		7,327		7,327	11
410		9,350		9,350	12
9,857		227,554		227,554	13
399		5,160		5,160	14
0	0	0	0	0	
1,185,879	0	22,766,467	2,438,518	25,204,985	
1,185,879	**0**	**22,766,467**	**2,438,518**	**25,204,985**	

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2017	End of 2016/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 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
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LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	EDF Trading North America, LLC	SF	WSPP	n/a	n/a	n/a
2	Energy Keepers	SF	WSPP	n/a	n/a	n/a
3	Eugene Electric Board	SF	WSPP	n/a	n/a	n/a
4	Exelon Generation Company. LLC	SF	WSPP	n/a	n/a	n/a
5	Exelon Generation Company. LLC	OS	WSPP	n/a	n/a	n/a
6	Los Angeles Department of Water & Power	SF	WSPP	n/a	n/a	n/a
7	Macquarie Energy LLC	SF	WSPP	n/a	n/a	n/a
8	Macquarie Energy LLC	OS	WSPP	n/a	n/a	n/a
9	Morgan Stanley Capital Group Inc.	SF	ISDA	n/a	n/a	n/a
10	Morgan Stanley Capital Group Inc.	OS	ISDA	n/a	n/a	n/a
11	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
12	Municipal Energy Agency of Nebraska	SF	WSPP	n/a	n/a	n/a
13	NV Energy	SF	WSPP	n/a	n/a	n/a
14	NV Energy	OS	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
37,544		553,422		553,422	1
382		9,189		9,189	2
2,513		39,535		39,535	3
111,210		2,625,370		2,625,370	4
			89,305	89,305	5
220,850		5,839,425		5,839,425	6
4		24		24	7
			317,348	317,348	8
56,485		756,679		756,679	9
238			5,474	5,474	10
			499,468	499,468	11
70		150		150	12
7,551		89,744		89,744	13
			2,117	2,117	14
0	0	0	0	0	
1,185,879	0	22,766,467	2,438,518	25,204,985	
1,185,879	**0**	**22,766,467**	**2,438,518**	**25,204,985**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	NorthWestern Energy	SF	WSPP	n/a	n/a	n/a
2	NorthWestern Energy	OS	WSPP	n/a	n/a	n/a
3	NorthWestern Energy	OS	WSPP	n/a	n/a	n/a
4	PacifiCorp Inc.	SF	WSPP	n/a	n/a	n/a
5	PacifiCorp Inc.	OS	T-7	n/a	n/a	n/a
6	Portland General Electric Company	SF	WSPP	n/a	n/a	n/a
7	Portland General Electric Company	OS	T-7	n/a	n/a	n/a
8	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
9	Powerex Corp.	SF	WSPP	n/a	n/a	n/a
10	Powerex Corp.	OS	WSPP	n/a	n/a	n/a
11	Powerex Corp.	OS	WSPP	n/a	n/a	n/a
12	Public Service of Colorado	SF	WSPP	n/a	n/a	n/a
13	Puget Sound Energy, Inc.	SF	WSPP	n/a	n/a	n/a
14	Puget Sound Energy, Inc.	OS	T-7	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
5,102		74,220		74,220	1
64			192	192	2
			6,013	6,013	3
11,282		160,279		160,279	4
36			836	836	5
124,937		2,675,748		2,675,748	6
12			244	244	7
			3,099	3,099	8
20,713		220,241		220,241	9
246			246	246	10
			70	70	11
3,600		67,920		67,920	12
14,496		210,788		210,788	13
4			81	81	14
0	0	0	0	0	
1,185,879	0	22,766,467	2,438,518	25,204,985	
1,185,879	**0**	**22,766,467**	**2,438,518**	**25,204,985**	

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 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Rainbow Energy Marketing Corporation	SF	WSPP	n/a	n/a	n/a
2	Salt River Project	SF	WSPP	n/a	n/a	n/a
3	Seattle City Light	SF	WSPP	n/a	n/a	n/a
4	Seattle City Light	OS	WSPP	n/a	n/a	n/a
5	Shell Energy North America (US), L.P.	SF	WSPP	n/a	n/a	n/a
6	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
7	Sierra Pacific Power Co., dba NV Energy	OS	T-7	n/a	n/a	n/a
8	Snohomish County PUD	SF	WSPP	n/a	n/a	n/a
9	Talen Energy Marketing, LLC.	SF	WSPP	n/a	n/a	n/a
10	Talen Energy Marketing, LLC.	OS	WSPP	n/a	n/a	n/a
11	Talen Energy Marketing, LLC.	OS	WSPP	n/a	n/a	n/a
12	Tenaska Power Services Co.	SF	WSPP	n/a	n/a	n/a
13	Tenaska Power Services Co.	OS	WSPP	n/a	n/a	n/a
14	The Energy Authority, Inc.	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
6,800		71,088		71,088	1
332		8,865		8,865	2
5,468		104,626		104,626	3
45			45	45	4
182,065		2,707,230		2,707,230	5
			73,235	73,235	6
98			1,938	1,938	7
605		12,180		12,180	8
7,391		84,130		84,130	9
			1,549	1,549	10
1,080			4,435	4,435	11
4,330		32,390		32,390	12
			376	376	13
160,594		2,978,971		2,978,971	14
0	0	0	0	0	
1,185,879	0	22,766,467	2,438,518	25,204,985	
1,185,879	**0**	**22,766,467**	**2,438,518**	**25,204,985**	

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 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
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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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Actual Demand (MW) Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	The Energy Authority, Inc.	OS	WSPP	n/a	n/a	n/a
2	TransAlta Energy Marketing (U.S.), Inc.	SF	WSPP	n/a	n/a	n/a
3	TransAlta Energy Marketing (U.S.), Inc.	OS	WSPP	n/a	n/a	n/a
4	Tri-State Generation and Transmission	SF	WSPP	n/a	n/a	n/a
5	Prior Year Write Off Recovered	AD	-	n/a	n/a	n/a
6	Transmission Penalty Distribution	OS	-	n/a	n/a	n/a
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			1,774	1,774	1
6,414		140,478		140,478	2
			4,401	4,401	3
75		175		175	4
			3,255	3,255	5
			6,337	6,337	6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
1,185,879	0	22,766,467	2,438,518	25,204,985	
1,185,879	**0**	**22,766,467**	**2,438,518**	**25,204,985**	

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Schedule Page: 310 Line No.: 1 Column: a
ADM Investor Services, Inc Futures Account Document, dated May 5, 2015
Schedule Page: 310 Line No.: 4 Column: a
Avangrid Renewables, LLC, Capacity Agreement, dated January 16, 2015
Schedule Page: 310 Line No.: 5 Column: a
Financial Transmission Losses
Schedule Page: 310 Line No.: 9 Column: a
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 5 Column: a
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 8 Column: a
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 10 Column: a
Non-firm Sales
Schedule Page: 310.1 Line No.: 11 Column: a
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 14 Column: a
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 2 Column: a
Non-firm sales
Schedule Page: 310.2 Line No.: 3 Column: a
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 5 Column: a
Spinning or operating reserves
Schedule Page: 310.2 Line No.: 7 Column: a
Spinning or operating reserves
Schedule Page: 310.2 Line No.: 8 Column: a
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 10 Column: a
Non-firm sales
Schedule Page: 310.2 Line No.: 11 Column: a
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 14 Column: a
Spinning or operating reserves
Schedule Page: 310.3 Line No.: 4 Column: a
Non-firm sales
Schedule Page: 310.3 Line No.: 6 Column: a
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 7 Column: a
Spinning or operating reserves
Schedule Page: 310.3 Line No.: 10 Column: a
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 11 Column: a
Non-firm sales
Schedule Page: 310.3 Line No.: 13 Column: a
Financial Transmission Losses
Schedule Page: 310.4 Line No.: 1 Column: a
Finanical Transmission Losses
Schedule Page: 310.4 Line No.: 3 Column: a
Financial Transmission Losses

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,158,861	1,287,887
5	(501) Fuel	137,688,753	131,286,356
6	(502) Steam Expenses	8,971,192	9,791,612
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,466,072	1,262,175
10	(506) Miscellaneous Steam Power Expenses	9,097,246	6,676,269
11	(507) Rents	206,742	432,038
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	158,588,866	150,736,337
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	100,102	126,993
16	(511) Maintenance of Structures	528,121	878,071
17	(512) Maintenance of Boiler Plant	14,263,344	13,861,559
18	(513) Maintenance of Electric Plant	5,150,575	5,412,553
19	(514) Maintenance of Miscellaneous Steam Plant	6,435,348	6,923,251
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	26,477,490	27,202,427
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	185,066,356	177,938,764
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	5,676,404	5,798,402
45	(536) Water for Power	6,025,791	9,070,347
46	(537) Hydraulic Expenses	14,667,285	14,907,949
47	(538) Electric Expenses	1,696,943	1,623,508
48	(539) Miscellaneous Hydraulic Power Generation Expenses	5,699,628	5,675,338
49	(540) Rents	235,365	235,266
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	34,001,416	37,310,810
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	116,729	120,335
54	(542) Maintenance of Structures	1,218,450	1,120,484
55	(543) Maintenance of Reservoirs, Dams, and Waterways	658,337	575,444
56	(544) Maintenance of Electric Plant	2,197,930	2,655,929
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,345,337	2,860,095
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,536,783	7,332,287
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	40,538,199	44,643,097

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	738,484	646,633
63	(547) Fuel	41,802,251	54,944,643
64	(548) Generation Expenses	4,155,511	4,603,907
65	(549) Miscellaneous Other Power Generation Expenses	807,061	934,376
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	47,503,307	61,129,559
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	400,817	363,695
71	(553) Maintenance of Generating and Electric Plant	126,988	71,909
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,764,692	1,270,216
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	3,292,497	1,705,820
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	50,795,804	62,835,379
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	240,208,728	217,596,604
77	(556) System Control and Load Dispatching	2,678	2,436
78	(557) Other Expenses	-1,206,336	20,615,245
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	239,005,070	238,214,285
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	515,405,429	523,631,525
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,953,141	4,136,382
84			
85	(561.1) Load Dispatch-Reliability	43,356	
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,602,644	1,757,323
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,390,552	1,159,643
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	25,459	21,585
92	(561.8) Reliability, Planning and Standards Development Services	1,634,564	
93	(562) Station Expenses	2,637,946	2,633,328
94	(563) Overhead Lines Expenses	953,376	967,338
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	5,555,121	6,279,133
97	(566) Miscellaneous Transmission Expenses	7,471	2,365
98	(567) Rents	4,139,757	3,084,849
99	TOTAL Operation (Enter Total of lines 83 thru 98)	20,943,387	20,041,946
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	169,832	157,051
102	(569) Maintenance of Structures	2,882	12,690
103	(569.1) Maintenance of Computer Hardware	27,827	23,408
104	(569.2) Maintenance of Computer Software	896,206	867,398
105	(569.3) Maintenance of Communication Equipment	15,105	29,123
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,220,242	3,286,329
108	(571) Maintenance of Overhead Lines	1,132,781	2,935,312
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	4,464,875	7,311,311
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	25,408,262	27,353,257

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	4,226,094	4,289,300
135	(581) Load Dispatching	4,026,028	3,897,253
136	(582) Station Expenses	1,544,740	1,339,544
137	(583) Overhead Line Expenses	3,606,076	3,968,009
138	(584) Underground Line Expenses	3,076,757	2,889,346
139	(585) Street Lighting and Signal System Expenses	82,633	87,956
140	(586) Meter Expenses	4,717,443	4,769,220
141	(587) Customer Installations Expenses	897,759	784,157
142	(588) Miscellaneous Expenses	7,518,466	6,041,032
143	(589) Rents	305,059	262,071
144	TOTAL Operation (Enter Total of lines 134 thru 143)	30,001,055	28,327,888
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	-1,554,525	10,627
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	3,870,899	3,630,618
149	(593) Maintenance of Overhead Lines	14,975,930	14,203,471
150	(594) Maintenance of Underground Lines	868,712	604,456
151	(595) Maintenance of Line Transformers	28,581	36,603
152	(596) Maintenance of Street Lighting and Signal Systems	588,626	486,847
153	(597) Maintenance of Meters	873,691	767,987
154	(598) Maintenance of Miscellaneous Distribution Plant	380,105	289,620
155	TOTAL Maintenance (Total of lines 146 thru 154)	20,032,019	20,030,229
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	50,033,074	48,358,117
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	617,373	484,451
160	(902) Meter Reading Expenses	1,649,267	1,843,348
161	(903) Customer Records and Collection Expenses	14,631,724	15,508,388
162	(904) Uncollectible Accounts	3,946,809	3,319,967
163	(905) Miscellaneous Customer Accounts Expenses	-551	395
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	20,844,622	21,156,549

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	796,990	807,713
168	(908) Customer Assistance Expenses	41,249,994	37,606,989
169	(909) Informational and Instructional Expenses	427,793	424,680
170	(910) Miscellaneous Customer Service and Informational Expenses	449,522	735,552
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	42,924,299	39,574,934
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	24	79,720
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	24	79,720
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	81,422,856	73,062,858
182	(921) Office Supplies and Expenses	14,772,947	14,719,911
183	(Less) (922) Administrative Expenses Transferred-Credit	33,792,414	26,120,468
184	(923) Outside Services Employed	8,226,785	8,177,858
185	(924) Property Insurance	3,362,154	3,382,607
186	(925) Injuries and Damages	5,991,970	6,644,800
187	(926) Employee Pensions and Benefits	52,679,051	45,004,540
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	3,818,396	3,616,257
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	582,063	618,107
192	(930.2) Miscellaneous General Expenses	3,552,222	5,444,853
193	(931) Rents		2,000
194	TOTAL Operation (Enter Total of lines 181 thru 193)	140,616,030	134,553,323
195	Maintenance		
196	(935) Maintenance of General Plant	6,271,101	5,817,078
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	146,887,131	140,370,401
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	801,502,841	800,524,503

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

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	AgPower Jerome / Double A Digester	LU	-	N/A	N/A	N/A
2	Allan Ravenscroft/Malad River	LU	-	.488Mw		
3	Baker City Hydro	LU	-	N/A	N/A	N/A
4	Bannock County, Idaho	LU	-	N/A	N/A	N/A
5	Bennett Creek Wind Farm	LU	-	N/A	N/A	N/A
6	Bettencourt DryCreek Biofactory	LU	-	N/A	N/A	N/A
7	Big Sky West Dairy Digester	LU	-	N/A	N/A	N/A
8	Big Wood Canal Company					
9	Black Canyon #3	LU	-	N/A	N/A	N/A
10	Jim Knight	LU	-	N/A	N/A	N/A
11	Sagebrush	LU	-	N/A	N/A	N/A
12	Black Canyon Bliss	LU	-	N/A	N/A	N/A
13	Blind Canyon Hydro	LU	-	N/A	N/A	N/A
14	Branchflower/Trout Company	LU	-	N/A	N/A	N/A
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
25,654				2,263,626		2,263,626	1
1,745			155,672	72,103		227,775	2
887				44,777		44,777	3
10,971				612,752		612,752	4
44,697				2,844,180		2,844,180	5
10,779				943,333		943,333	6
8,693				563,960		563,960	7
							8
267				19,069		19,069	9
902				67,009		67,009	10
804				59,031		59,031	11
157				3,346		3,346	12
3,347				139,107		139,107	13
701				50,151		50,151	14
4,330,800	234,717	181,766	2,815,124	228,585,769	8,807,835	240,208,728	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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:

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Burley Butte Wind Park	LU	-	N/A	N/A	N/A
2	Bypass Limited	LU	-	N/A	N/A	N/A
3	Camp Reed Wind Park	LU		N/A	N/A	N/A
4	Cargill Inc./B6 Anaerobic Digester	LU	-	N/A	N/A	N/A
5	Cassia Wind Farm	LU	-	N/A	N/A	N/A
6	CCP OR Tenant 1, LLC - Grove	LU	-	N/A	N/A	N/A
7	CCP OR Tenant 1, LLC - Hyline	LU	-	N/A	N/A	N/A
8	CCP OR Tenant 1, LLC - Open Range	LU	-	N/A	N/A	N/A
9	CCP OR Tenant 1, LLC - Railroad	LU	-	N/A	N/A	N/A
10	CCP OR Tenant 1, LLC - Vale Air	LU	-	N/A	N/A	N/A
11	CCP OR Tenant 1, LLC - Thunderegg	LU	-	N/A	N/A	N/A
12	City of Cove, Oregon / Mill Creek	LU	-	N/A	N/A	N/A
13	City of Hailey	LU	-	N/A	N/A	N/A
14	City of Pocatello	LU	-	N/A	N/A	N/A
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
56,379				3,224,076		3,224,076	1
26,060				1,421,768		1,421,768	2
69,005				5,811,842		5,811,842	3
10,378				896,225		896,225	4
24,506				1,470,877		1,470,877	5
941				53,069		53,069	6
630				36,930		36,930	7
2,267				131,506		131,506	8
224				11,954		11,954	9
1,155				66,453		66,453	10
743				37,654		37,654	11
2,870				204,185		204,185	12
60				-47,793		-47,793	13
1,359				99,384		99,384	14
4,330,800	234,717	181,766	2,815,124	228,585,769	8,807,835	240,208,728	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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:

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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	Clear Springs Food Inc.	LU	-	N/A	N/A	N/A
2	Clifton E. Jenson/Birch Creek	LU	-	.05Mw		
3	Cold Springs Windfarm, LLC	LU	-	N/A	N/A	N/A
4	Consolidated Hydro Inc. / Enel					
5	Barber Dam	LU	-	N/A	N/A	N/A
6	Dietrich Drop	LU	-	N/A	N/A	N/A
7	GeoBon #2	LU	-	N/A	N/A	N/A
8	Lowline #2	LU	-	N/A	N/A	N/A
9	Rock Creek #2	LU	-	N/A	N/A	N/A
10	Contractors Power Group Inc./Mile 28	LU	-	N/A	N/A	N/A
11	Crystal Springs Hydro	LU	-	N/A	N/A	N/A
12	Curry Cattle Company	LU	-	.084Mw		
13	David McCollum/Canyon Springs	LU	-	N/A	N/A	N/A
14	David R Snedigar	LU	-	N/A	N/A	N/A
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,500				340,642		340,642	1
340			17,500	14,033		31,533	2
53,617				3,832,996		3,832,996	3
							4
12,078				608,959		608,959	5
13,788				774,856		774,856	6
3,007				232,422		232,422	7
8,110				434,107		434,107	8
7,217				357,601		357,601	9
4,625				327,934		327,934	10
11,021				750,782		750,782	11
679			26,796	28,067		54,863	12
560				7,913		7,913	13
1,371				94,516		94,516	14
4,330,800	234,717	181,766	2,815,124	228,585,769	8,807,835	240,208,728	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Desert Meadow Wind Farm	LU	-	N/A	N/A	N/A
2	Eightmile Hydro Corp	LU	-	N/A	N/A	N/A
3	Faulkner Brothers Hydro Inc.	LU	-	N/A	N/A	N/A
4	Fisheries Development	OS	-	N/A	N/A	N/A
5	Fossil Gulch Wind	LU	-	N/A	N/A	N/A
6	G2 Energy Hidden Hollow	LU	-	N/A	N/A	N/A
7	Golden Valley Wind Park	LU	-	N/A	N/A	N/A
8	Grand View PV Solar Two, LLC	LU	-	N/A	N/A	N/A
9	Hammett Hill Windfarm, LLC	LU	-	N/A	N/A	N/A
10	Hazelton B Power Company	LU	-	N/A	N/A	N/A
11	Head of U Canal	LU	-	N/A	N/A	N/A
12	High Mesa Energy	LU	-	N/A	N/A	N/A
13	H.K. Hydro Mud Creek S & S	LU	-	N/A	N/A	N/A
14	Horseshoe Bend Hydro	LU	-	N/A	N/A	N/A
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
61,815				4,419,722		4,419,722	1
1,501				82,325		82,325	2
3,263				254,932		254,932	3
1,078				15,302		15,302	4
25,760				1,487,927		1,487,927	5
22,044				1,419,338		1,419,338	6
31,284				1,782,166		1,782,166	7
3,582				168,000		168,000	8
60,624				4,323,037		4,323,037	9
21,934				1,577,844		1,577,844	10
4,389				355,548		355,548	11
99,240				4,874,853		4,874,853	12
1,625				138,874		138,874	13
46,500				3,222,725		3,222,725	14
4,330,800	234,717	181,766	2,815,124	228,585,769	8,807,835	240,208,728	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

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	Horseshoe Bend Wind/United Materials	LU	-	N/A	N/A	N/A
2	Hot Springs Wind Farm	LU	-	N/A	N/A	N/A
3	ID Solar 1, LLC	LU	-	N/A	N/A	N/A
4	Idaho Winds / Sawtooth Wind Project	LU	-	N/A	N/A	N/A
5	J R Simplot Co.	LU	-	N/A	N/A	N/A
6	J.M. Miller/Sahko Hydro	LU	-	N/A	N/A	N/A
7	James B. Howell / CHI Elk Creek	LU	-	N/A	N/A	N/A
8	John R LeMoyne	LU	-	N/A	N/A	N/A
9	Kasel & Witherspoon	LU	-	N/A	N/A	N/A
10	Kootenai Electric Cooperative / Fighti	LU	-	N/A	N/A	N/A
11	Koyle Hydro Inc.	LU	-	N/A	N/A	N/A
12	Lateral 10 Ventures	LU	-	N/A	N/A	N/A
13	Lemhi Hydro Power Co./Schaffner	LU	-	N/A	N/A	N/A
14	Lime Wind	LU	-	N/A	N/A	N/A
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) 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 (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) 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 column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
18,172				1,059,560		1,059,560	1
40,876				2,548,880		2,548,880	2
26,220				618,344		618,344	3
60,872				4,969,395		4,969,395	4
65,048				2,888,782		2,888,782	5
1,383				108,374		108,374	6
2,147				154,777		154,777	7
626				35,340		35,340	8
3,760				336,989		336,989	9
10,823				836,703		836,703	10
3,330				315,068		315,068	11
6,667				421,458		421,458	12
1,341				98,611		98,611	13
5,867				423,272		423,272	14
4,330,800	234,717	181,766	2,815,124	228,585,769	8,807,835	240,208,728	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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:

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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.

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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	Little Mac Power Co./Cedar Draw	LU	-	N/A	N/A	N/A
2	Little Wood River Irrigation District	LU	-	N/A	N/A	N/A
3	Magic Reservoir Hydro	LU	-	N/A	N/A	N/A
4	Mainline Windfarm	LU	-	N/A	N/A	N/A
5	Marco Rancher's Irrigation Inc.	LU	-	N/A	N/A	N/A
6	Marysville Hydro Partners/Falls River	LU	-	N/A	N/A	N/A
7	Milner Dam Wind Park	LU	-	N/A	N/A	N/A
8	Mud Creek White Hydro, Inc	LU	-	N/A	N/A	N/A
9	New Energy One / Rock Creek Dairy	LU	-	N/A	N/A	N/A
10	North Gooding Main, Hydro	LU	-	N/A	N/A	N/A
11	Oregon Trail Wind Park	LU	-	N/A	N/A	N/A
12	Owyhee Irrigation District					
13	Mitchell Butte	LU	-	N/A	N/A	N/A
14	Owyhee Dam	LU	-	N/A	N/A	N/A
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5,764				377,413		377,413	1
4,770				345,423		345,423	2
16,892				931,945		931,945	3
58,640				4,192,744		4,192,744	4
2,930				200,647		200,647	5
37,751				2,429,636		2,429,636	6
52,558				2,990,322		2,990,322	7
509				34,180		34,180	8
13,436				1,060,717		1,060,717	9
6				277		277	10
38,581				2,233,100		2,233,100	11
							12
3,789				115,386		115,386	13
13,366				332,150		332,150	14
4,330,800	234,717	181,766	2,815,124	228,585,769	8,807,835	240,208,728	

PURCHASED POWER (Account 555)
(Including power exchanges)

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.
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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.

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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.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Tunnel #1	LU	-	N/A	N/A	N/A
2	Paynes Ferry Wind Park	LU	-	N/A	N/A	N/A
3	Pigeon Cove Power	LU	-	1.389		
4	Pilgrim Stage Station Wind Park	LU	-	N/A	N/A	N/A
5	Pristine Springs Inc #1	LU	-	N/A	N/A	N/A
6	Pristine Springs Inc. #3	LU	-	N/A	N/A	N/A
7	Reynolds Irrigation District	LU	-	N/A	N/A	N/A
8	Richard Kaster					
9	Box Canyon	LU	-	N/A	N/A	N/A
10	Briggs Creek	LU	-	N/A	N/A	N/A
11	Riverside Hydro/Mora Drop	LU	-	N/A	N/A	N/A
12	Riverside Investments					
13	Arena Drop	LU	-	N/A	N/A	N/A
14	Fargo Drop	LU	-	N/A	N/A	N/A
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
10,561				1,175,186		1,175,186	1
66,766				5,640,875		5,640,875	2
8,809			486,150	316,687		802,837	3
31,054				1,813,196		1,813,196	4
740				41,108		41,108	5
1,308				76,806		76,806	6
1,203				91,025		91,025	7
							8
1,859				121,817		121,817	9
3,522				240,240		240,240	10
4,848				287,026		287,026	11
							12
1,690				136,002		136,002	13
3,740				213,774		213,774	14
4,330,800	234,717	181,766	2,815,124	228,585,769	8,807,835	240,208,728	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Rock Creek #1 Joint Venture	LU	-	1.732Mw		
2	Rockland Wind Project	LU	-	N/A	N/A	N/A
3	Rupert Cogeneration Partners/Magic Val	LU	-	N/A	N/A	N/A
4	Ryegrass Windfarm	LU	-	N/A	N/A	N/A
5	Salmon Falls Wind Park	LU	-	N/A	N/A	N/A
6	SE Hazelton A LP	LU	-	N/A	N/A	N/A
7	Shorock Hydro Inc.					
8	Shoshone CSPP	LU	-	N/A	N/A	N/A
9	Shoshone #2	LU	-	N/A	N/A	N/A
10	Snake River Pottery	LU	-	N/A	N/A	N/A
11	South Forks Joint Venture/Lowline Cana	LU	-	N/A	N/A	N/A
12	Tamarack Energy Partnership	LU	-	4.942Mw		
13	Tasco - Nampa	OS	-	N/A	N/A	N/A
14	Tasco - Twin Falls	OS	-	N/A	N/A	N/A
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
10,881			552,508	449,725		1,002,233	1
252,235				16,273,689		16,273,689	2
65,827				4,390,141		4,390,141	3
56,948				4,069,575		4,069,575	4
62,402				3,579,890		3,579,890	5
22,449				1,695,734		1,695,734	6
							7
1,518				139,963		139,963	8
2,163				154,558		154,558	9
361				24,528		24,528	10
26,604				1,940,798		1,940,798	11
26,307			1,576,498	1,239,453		2,815,951	12
455				7,565		7,565	13
							14
4,330,800	234,717	181,766	2,815,124	228,585,769	8,807,835	240,208,728	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Ted S. Sorenson/Tiber Dam	LU	-	N/A	N/A	N/A
2	Thousand Springs Wind Park	LU	-	N/A	N/A	N/A
3	Tuana Gulch Wind Park	LU	-	N/A	N/A	N/A
4	Tuana Springs Expansion	LU	-	N/A	N/A	N/A
5	Twin Falls Energy/Lowline Midway Hydro	LU	-	N/A	N/A	N/A
6	Two Ponds Windfarm	LU	-	N/A	N/A	N/A
7	White Water Ranch	LU	-	N/A	N/A	N/A
8	William Arkoosh/Littlewood	LU	-	N/A	N/A	N/A
9	Littlewood River Ranch II	LU	-	N/A	N/A	N/A
10	Willis and Betty Deveny/Shingle Creek	LU	-	N/A	N/A	N/A
11	Wilson Power Company	LU	-	N/A	N/A	N/A
12	Yahoo Creek Wind Park	LU	-	N/A	N/A	N/A
13	Scheduling Deviation	OS	-	N/A	N/A	N/A
14	Other Purchased Power					
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
29,859				1,711,990		1,711,990	1
34,029				1,972,862		1,972,862	2
30,264				1,747,502		1,747,502	3
77,819				5,194,036		5,194,036	4
8,281				515,642		515,642	5
62,172				4,437,570		4,437,570	6
638				43,446		43,446	7
3,090				236,663		236,663	8
3,481				216,295		216,295	9
956				73,069		73,069	10
25,580				1,840,717		1,840,717	11
66,803				5,653,659		5,653,659	12
103							13
							14
4,330,800	234,717	181,766	2,815,124	228,585,769	8,807,835	240,208,728	

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	ADM Investor Services, Inc.	OS	-	N/A	N/A	N/A
2	Arizona Public Service Co.	SF	WSPP	N/A	N/A	N/A
3	Arizona Public Service Co.	OS	WSPP	N/A	N/A	N/A
4	Avangrid Renewables, LLC	SF	WSPP	N/A	N/A	N/A
5	Avista Corp.	OS	T-12	N/A	N/A	N/A
6	Avista Corp.	SF	WSPP	N/A	N/A	N/A
7	Avista Corp.	OS	WSPP	N/A	N/A	N/A
8	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
9	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
10	Bonneville Power Administration	SF	WSPP	N/A	N/A	N/A
11	BP Energy Company	SF	WSPP	N/A	N/A	N/A
12	Calpine Energy Services, L.P.	OS	WSPP	N/A	N/A	N/A
13	Calpine Energy Services, L.P.	SF	WSPP	N/A	N/A	N/A
14	Cargill Power Markets LLC	SF	WSPP	N/A	N/A	N/A
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					-356,330	-356,330	1
40,900				1,290,600		1,290,600	2
					282	282	3
32,774				838,587		838,587	4
69					1,574	1,574	5
28,310				626,752		626,752	6
					120,089	120,089	7
					312,501	312,501	8
439					9,871	9,871	9
89,496				2,161,126		2,161,126	10
3,800				82,510		82,510	11
4					57	57	12
18,000				456,938		456,938	13
4,466				104,586		104,586	14
4,330,800	234,717	181,766	2,815,124	228,585,769	8,807,835	240,208,728	

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Cargill Power Markets LLC	OS	ISDA	N/A	N/A	N/A
2	Chelan Co PUD	SF	WSPP	N/A	N/A	N/A
3	Chelan Co PUD	OS	WSPP	N/A	N/A	N/A
4	Citigroup Energy Inc.	SF	WSPP	N/A	N/A	N/A
5	Citigroup Energy Inc.	OS	ISDA	N/A	N/A	N/A
6	Clatskanie PUD	SF	WSPP	N/A	N/A	N/A
7	Douglas County PUD	OS	WSPP	N/A	N/A	N/A
8	EDF Trading North America, LLC	SF	WSPP	N/A	N/A	N/A
9	Energy Keepers	SF	WSPP	N/A	N/A	N/A
10	Eugene Water & Electric Board	SF	WSPP	N/A	N/A	N/A
11	Exelon Generation Company, LLC	SF	WSPP	N/A	N/A	N/A
12	Grant CO Public Utility District #2 --	OS	WSPP	N/A	N/A	N/A
13	Gridforce Energy Management, LLC.	OS	NWPP	N/A	N/A	N/A
14	Los Angeles Department of Water & Powe	SF	WSPP	N/A	N/A	N/A
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					-27,076	-27,076	1
28,000				546,632		546,632	2
18					438	438	3
45,200					1,262,888	1,262,888	4
					-17,429	-17,429	5
43				385		385	6
10					241	241	7
185,025				4,134,111		4,134,111	8
5,000				119,774		119,774	9
2,220				40,000		40,000	10
8,000				197,790		197,790	11
37					849	849	12
11					300	300	13
332				8,941		8,941	14
4,330,800	234,717	181,766	2,815,124	228,585,769	8,807,835	240,208,728	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Macquarie Energy LLC	SF	WSPP	N/A	N/A	N/A
2	Macquarie Energy LLC	OS	ISDA	N/A	N/A	N/A
3	Morgan Stanley Capital Group Inc.	SF	ISDA	N/A	N/A	N/A
4	Morgan Stanley Capital Group Inc.	SF	ISDA	N/A	N/A	N/A
5	Nevada Power Company, DBA NV Energy	SF	WSPP	N/A	N/A	N/A
6	Nevada Power Company, DBA NV Energy	OS	WSPP	N/A	N/A	N/A
7	NorthWestern Energy	OS	T-7	N/A	N/A	N/A
8	NorthWestern Energy	OS	WSPP	N/A	N/A	N/A
9	NorthWestern Energy	SF	WSPP	N/A	N/A	N/A
10	PacifiCorp Inc.	OS	T-13	N/A	N/A	N/A
11	PacifiCorp Inc.	SF	WSPP	N/A	N/A	N/A
12	PacifiCorp Inc.	OS	WSPP	N/A	N/A	N/A
13	Portland General Electric Company	OS	T-14	N/A	N/A	N/A
14	Portland General Electric Company	SF	WSPP	N/A	N/A	N/A
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
15,800					371,258	371,258	1
					-141,724	-141,724	2
13,356				369,663		369,663	3
					-43,049	-43,049	4
15,750				605,225		605,225	5
					82	82	6
58					1,436	1,436	7
3					9	9	8
3,747				77,846		77,846	9
357					8,084	8,084	10
57,347				1,517,884		1,517,884	11
					-21,381	-21,381	12
107					2,541	2,541	13
28,112				747,542		747,542	14
4,330,800	234,717	181,766	2,815,124	228,585,769	8,807,835	240,208,728	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Powerex Corp.	SF	WSPP	N/A	N/A	N/A
2	Public Service Company of Colorado	SF	WSPP	N/A	N/A	N/A
3	Puget Sound Energy, Inc.	OS	T-9	N/A	N/A	N/A
4	Puget Sound Energy, Inc.	SF	WSPP	N/A	N/A	N/A
5	Rainbow Energy Marketing Corporation	OS	WSPP	N/A	N/A	N/A
6	Salt River Project	SF	WSPP	N/A	N/A	N/A
7	Seattle City Light	OS	WSPP	N/A	N/A	N/A
8	Seattle City Light	SF	WSPP	N/A	N/A	N/A
9	Shell Energy North America (US), L.P.	SF	WSPP	N/A	N/A	N/A
10	Sierra Pacific Power Co., dba NV Energ	OS	T-55	N/A	N/A	N/A
11	Sierra Pacific Power Co., dba NV Energ	OS	WSPP	N/A	N/A	N/A
12	Snohomish County PUD	SF	WSPP	N/A	N/A	N/A
13	Tacoma Power	OS	WSPP	N/A	N/A	N/A
14	Tacoma Power	SF	WSPP	N/A	N/A	N/A
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
86,484				2,688,154		2,688,154	1
17,200				370,888		370,888	2
121					2,806	2,806	3
50,212				1,037,994		1,037,994	4
1,192					20,862	20,862	5
331,600				8,424,105		8,424,105	6
49					1,105	1,105	7
43,217				857,362		857,362	8
36,089				696,584		696,584	9
176					4,132	4,132	10
14					346	346	11
5,450				107,921		107,921	12
23					547	547	13
5,770				127,775		127,775	14
4,330,800	234,717	181,766	2,815,124	228,585,769	8,807,835	240,208,728	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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:

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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.

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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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Talen Energy	SF	WSPP	N/A	N/A	N/A
2	Talen Energy	OS	WSPP	N/A	N/A	N/A
3	Tenaska Power Services Co.	SF	WSPP	N/A	N/A	N/A
4	The Energy Authority, Inc.	SF	WSPP	N/A	N/A	N/A
5	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	N/A	N/A	N/A
6	Tucson Electric Power Company	SF	WSPP	N/A	N/A	N/A
7	Turlock Irrigation District	SF	WSPP	N/A	N/A	N/A
8	Western Area Power Administration (UGP	OS	WSPP	N/A	N/A	N/A
9	Raft River Energy I LLC	LU	-	N/A	N/A	N/A
10	Telocaset Wind Power Partners LLC	LU	APP-A	N/A	N/A	N/A
11	Neal Hot Springs Unit #1	LU	-	N/A	N/A	N/A
12	Oregon Solar Customers	OS	-	N/A	N/A	N/A
13	Power Exchanges					
14	Avista Corp.	EX	-			
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
134,565				3,404,167		3,404,167	1
4,816					125,593	125,593	2
69				2,616		2,616	3
12,573				213,677		213,677	4
75,904				1,862,696		1,862,696	5
100				2,500		2,500	6
106				1,852		1,852	7
1					30	30	8
71,990				4,775,686		4,775,686	9
331,666				19,682,018		19,682,018	10
179,560				19,552,582		19,552,582	11
880					15,383	15,383	12
							13
	5,574						14
4,330,800	234,717	181,766	2,815,124	228,585,769	8,807,835	240,208,728	

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Bonneville Power Administration	EX	-			
2	NorthWestern Energy	EX	-			
3	PacifiCorp Inc.	EX	-			
4	Sierra Pacific Power Co., dba NV Energ	EX	-			
5	Clatskanie PUD	EX	153			
6	Other Transactions					
7	Acctg Valuation of Clatskanie PUD	OS	-	N/A	N/A	N/A
8	Demand Response Avoided Energy	OS	-	N/A	N/A	N/A
9						
10						
11						
12						
13						
14						
	Total					

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	65,916						1
		192					2
	96,367	120,059					3
	71	1,115					4
	66,789	60,400					5
							6
					92,100	92,100	7
					7,059,420	7,059,420	8
							9
							10
							11
							12
							13
							14
4,330,800	234,717	181,766	2,815,124	228,585,769	8,807,835	240,208,728	

Schedule Page: 326 Line No.: 2 Column: e
Unavailable
Schedule Page: 326 Line No.: 2 Column: f
Unavailable
Schedule Page: 326.1 Line No.: 13 Column: a
Includes recovery of prior period overpayments
Schedule Page: 326.2 Line No.: 2 Column: e
Unavailable
Schedule Page: 326.2 Line No.: 2 Column: f
Unavailable
Schedule Page: 326.2 Line No.: 12 Column: e
Unavailable
Schedule Page: 326.2 Line No.: 12 Column: f
Unavailable
Schedule Page: 326.3 Line No.: 4 Column: b
Non-firm Purchases
Schedule Page: 326.3 Line No.: 10 Column: a
Ida West, a subsidary of Idaho Power Company, has partial ownership of these projects
Schedule Page: 326.5 Line No.: 6 Column: a
Ida West, a subsidary of Idaho Power Company, has partial ownership of these projects
Schedule Page: 326.6 Line No.: 3 Column: e
Unavailable
Schedule Page: 326.6 Line No.: 3 Column: f
Unavailable
Schedule Page: 326.7 Line No.: 1 Column: e
Unavailable
Schedule Page: 326.7 Line No.: 1 Column: f
Unavailable
Schedule Page: 326.7 Line No.: 11 Column: a
Ida West, a subsidary of Idaho Power Company, has partial ownership of these projects
Schedule Page: 326.7 Line No.: 12 Column: a
The Tamarack Energy Partnership demand readings are taken from an electronic demand recorder provided by Idaho Power Company. The actual demnad is not used in determining the cost of energy.
Schedule Page: 326.7 Line No.: 12 Column: e
Unavailable
Schedule Page: 326.7 Line No.: 12 Column: f
Unavailable
Schedule Page: 326.7 Line No.: 13 Column: b
Non-firm Purchases
Schedule Page: 326.7 Line No.: 14 Column: b
Non-firm Purchases
Schedule Page: 326.8 Line No.: 11 Column: a
Ida West, a subsidary of Idaho Power Company, has partial ownership of these projects
Schedule Page: 326.8 Line No.: 13 Column: b
Difference between booked and scheduled energy
Schedule Page: 326.9 Line No.: 1 Column: b
ADM Investor Services, Inc. Futures Account Document dated 5/5/2015
Schedule Page: 326.9 Line No.: 3 Column: b
Financial Transmission Losses
Schedule Page: 326.9 Line No.: 5 Column: b
Spinning or Operating Reserves
Schedule Page: 326.9 Line No.: 7 Column: b
Financial Transmission Losses

Schedule Page: 326.9 Line No.: 8 Column: b
Financial Transmission Losses
Schedule Page: 326.9 Line No.: 9 Column: b
Spinning or Operating Reserves
Schedule Page: 326.9 Line No.: 12 Column: b
Spinning or Operating Reserves
Schedule Page: 326.10 Line No.: 1 Column: b
ISDA Master Agreement with Cargill Power Markets, LLC, dated 6/13/2011
Schedule Page: 326.10 Line No.: 3 Column: b
Spinning or Operating Reserves
Schedule Page: 326.10 Line No.: 5 Column: b
ISDA Master Agreement with Citigroup Energy, Inc, dated 3/7/2011
Schedule Page: 326.10 Line No.: 7 Column: b
Spinning or Operating Reserves
Schedule Page: 326.10 Line No.: 12 Column: b
Spinning or Operating Reserves
Schedule Page: 326.10 Line No.: 13 Column: b
Spinning or Operating Reserves
Schedule Page: 326.11 Line No.: 2 Column: b
ISDA Master Agreement with Macquarie Energy, LLC, dated 4/12/2011
Schedule Page: 326.11 Line No.: 6 Column: b
Financial Transmission Losses
Schedule Page: 326.11 Line No.: 7 Column: b
Spinning or Operating Reserves
Schedule Page: 326.11 Line No.: 8 Column: b
Spinning or Operating Reserves
Schedule Page: 326.11 Line No.: 10 Column: b
Spinning or Operating Reserves
Schedule Page: 326.11 Line No.: 12 Column: b
Financial Transmission Losses
Schedule Page: 326.11 Line No.: 13 Column: b
Spinning or Operating Reserves
Schedule Page: 326.12 Line No.: 3 Column: b
Spinning or Operating Reserves
Schedule Page: 326.12 Line No.: 5 Column: b
Non-firm Purchases
Schedule Page: 326.12 Line No.: 7 Column: b
Spinning or Operating Reserves
Schedule Page: 326.12 Line No.: 10 Column: b
Spinning or Operating Reserves
Schedule Page: 326.12 Line No.: 11 Column: b
Spinning or Operating Reserves
Schedule Page: 326.12 Line No.: 13 Column: b
Spinning or Operating Reserves
Schedule Page: 326.13 Line No.: 2 Column: b
Unit Contingent Purchases
Schedule Page: 326.13 Line No.: 8 Column: b
Spinning or Operating Reserves
Schedule Page: 326.13 Line No.: 12 Column: b
Schedule 88 Oregon Solar
Schedule Page: 326.13 Line No.: 14 Column: b
Finanical Transmission Losses
Schedule Page: 326.14 Line No.: 1 Column: b
Finanical Transmission Losses
Schedule Page: 326.14 Line No.: 2 Column: b

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Finanical Transmission Losses

Schedule Page: 326.14 Line No.: 3 Column: b

Finanical Transmission Losses

Schedule Page: 326.14 Line No.: 4 Column: b

Finanical Transmission Losses

Schedule Page: 326.14 Line No.: 5 Column: b

Energy exchange between Clatskanie and Idaho Power Company at Arrowrock Dam

Schedule Page: 326.14 Line No.: 7 Column: b

Energy exchange between Clatskanie and Idaho Power Company at Arrowrock Dam

Schedule Page: 326.14 Line No.: 8 Column: b

Incentive program for customers to reduce demand during peak hours

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

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 Classifi-cation (d)
1	Bonneville Power Administration - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	FNO
2	Bonneville Power Administration - USBR	Bonneville Power Administration	United States Bureau of Reclamati	FNO
3	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	FNO
4	PacifiCorp - Imnaha	PacifiCorp West	PacifiCorp West	FNO
5	Milner Irrigation District	United States Bureau of Reclamati	Milner Irrigation District	OLF
6	United States Bureau of Indian Affairs	Bonneville Power Administration	United States Bureau of Indian Af	OS
7	Morgan Stanley Capital Group Inc.	Seattle City Light	Bonneville Power Administration	OS
8	United Materials of Great Falls	PacifiCorp East	Idaho Power Company	OS
9	United Materials of Great Falls	PacifiCorp East	Idaho Power Company	OS
10	United Materials of Great Falls	PacifiCorp East	Idaho Power Company	OS
11				
12	Bonneville Power Administration	PacifiCorp West	PacifiCorp East	LFP
13	Bonneville Power Administration	PacifiCorp West	PacifiCorp East	LFP
14	PacifiCorp Inc.	PacifiCorp East	Bonneville Power Administration	LFP
15	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	LFP
16	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	LFP
17	Morgan Stanley Capital Group Inc.	Idaho Power Company	Bonneville Power Administration	LFP
18				
19	Black Hills Power	PacifiCorp East	PacifiCorp East	NF
20	Bonneville Power Administration	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
21	Bonneville Power Administration	Bonneville Power Administration	PacifiCorp East	NF
22	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	NF
23	Bonneville Power Administration	Bonneville Power Administration	Sierra Pacific Power	NF
24	Bonneville Power Administration	Bonneville Power Administration	Sierra Pacific Power	SFP
25	Bonneville Power Administration	Avista	PacifiCorp East	NF
26	Bonneville Power Administration	Avista	Bonneville Power Administration	NF
27	Bonneville Power Administration	Avista	Sierra Pacific Power	NF
28	Bonneville Power Administration	Avista	Bonneville Power Administration	NF
29	Iberdrola Renewables LLC	PacifiCorp East	Bonneville Power Administration	NF
30	Iberdrola Renewables LLC	NorthWestern/PacifiCorp East	PacifiCorp East	NF
31	Iberdrola Renewables LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
32	Iberdrola Renewables LLC	Bonneville Power Administration	PacifiCorp East	NF
33	Iberdrola Renewables LLC	Bonneville Power Administration	Sierra Pacific Power	NF
34	Iberdrola Renewables LLC	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

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.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
9				338,338	338,338	1
9				281,205	281,205	2
9				1,257,463	1,257,463	3
9				2,133	2,133	4
Legacy	Minidoka, Idaho	Various in Idaho		9,407	9,407	5
Legacy	LaGrande, Oregon	Various in Idaho		14,870	14,870	6
4				340,288	340,288	7
5/6				2,935	2,935	8
5/6				4,647	4,647	9
5/6				10,347	10,347	10
						11
7/8	M500	KPRT		31,600	31,600	12
7/8	SMLK	KPRT		75,285	75,285	13
7/8	BORA	LAGRANDE		447,747	447,747	14
7/8	BORA	HURR		1,250,676	1,250,676	15
7/8	KPRT	HURR		492,190	492,190	16
7/8	LYPK	LAGRANDE		45,224	45,224	17
						18
7/8	BORA	BRDY		15	15	19
7/8	BPAT.NWMT	M345		16,290	16,290	20
7/8	LAGRANDE	KPRT		22	22	21
7/8	LAGRANDE	LAGRANDE		2,701	2,701	22
7/8	LAGRANDE	M345		24,418	24,418	23
7/8	LAGRANDE	M345		1,073	1,073	24
7/8	LOLO	BORA		2	2	25
7/8	LOLO	LAGRANDE		675	675	26
7/8	LOLO	M345		4,325	4,325	27
7/8	LOLO	OTEC		31	31	28
7/8	BORA	LAGRANDE		78	78	29
7/8	BPAT.NWMT	BRDY		83	83	30
7/8	BPAT.NWMT	M345		50	50	31
7/8	LAGRANDE	BORA		3,869	3,869	32
7/8	LAGRANDE	M345		4,022	4,022	33
7/8	M345	BPAT.NWMT		390	390	34
			0	**6,319,072**	**6,319,072**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

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)
1	Iberdrola Renewables LLC	Sierra Pacific Power	Bonneville Power Administration	NF
2	Iberdrola Renewables LLC	PacifiCorp West	PacifiCorp East	NF
3	Iberdrola Renewables LLC	PacifiCorp West	Sierra Pacific Power	NF
4	ID Solar I			NF
5	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
6	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
7	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
8	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
9	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	SFP
10	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Avista	NF
11	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
12	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
13	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
14	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
15	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
16	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
17	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp West	NF
18	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
19	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
20	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	NF
21	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	SFP
22	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
23	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
24	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	SFP
25	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	NF
26	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
27	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
28	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	NF
29	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	NF
30	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
31	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
32	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	SFP
33	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp East	NF
34	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp East	NF
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

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.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
7/8	M345	LAGRANDE		1,073	1,073	1
7/8	SMLK	BORA		3,141	3,141	2
7/8	SMLK	M345		791	791	3
7/8						4
7/8	AVAT.NWMT	BORA		4,109	4,109	5
7/8	AVAT.NWMT	BORA		10,908	10,908	6
7/8	AVAT.NWMT	BRDY		34	34	7
7/8	AVAT.NWMT	LAGRANDE		31,034	31,034	8
7/8	AVAT.NWMT	LAGRANDE		17,629	17,629	9
7/8	AVAT.NWMT	LOLO		187	187	10
7/8	AVAT.NWMT	M345		27,914	27,914	11
7/8	AVAT.NWMT	M345		14,289	14,289	12
7/8	BORA	LAGRANDE		590	590	13
7/8	BORA	M345		75	75	14
7/8	BPAT.NWMT	BORA		309	309	15
7/8	BPAT.NWMT	BRDY		51	51	16
7/8	BPAT.NWMT	HURR		25	25	17
7/8	BPAT.NWMT	LAGRANDE		3,445	3,445	18
7/8	BPAT.NWMT	M345		8,695	8,695	19
7/8	BRDY	BORA		1,435	1,435	20
7/8	BRDY	BORA		35	35	21
7/8	BRDY	LAGRANDE		7,694	7,694	22
7/8	BRDY	M345		37,869	37,869	23
7/8	BRDY	M345		44,641	44,641	24
7/8	JBSN	BORA		959	959	25
7/8	JBSN	LAGRANDE		213	213	26
7/8	JBSN	M345		1,224	1,224	27
7/8	JEFF	BORA		12,976	12,976	28
7/8	JEFF	BRDY		80	80	29
7/8	JEFF	LAGRANDE		4,025	4,025	30
7/8	JEFF	M345		66,210	66,210	31
7/8	JEFF	M345		66	66	32
7/8	LAGRANDE	BORA		9,214	9,214	33
7/8	LAGRANDE	BRDY		572	572	34
			0	**6,319,072**	**6,319,072**	

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.

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)
1	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
2	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	NF
3	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	SFP
4	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	NF
5	Morgan Stanley Capital Group Inc.	Avista	Sierra Pacific Power	NF
6	Morgan Stanley Capital Group Inc.	Avista	Sierra Pacific Power	SFP
7	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
8	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	SFP
9	Morgan Stanley Capital Group Inc.	Idaho Power Company	NorthWestern/PacifiCorp East	NF
10	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
11	Morgan Stanley Capital Group Inc.	Idaho Power Company	Avista	NF
12	Morgan Stanley Capital Group Inc.	Idaho Power Company	Sierra Pacific Power	NF
13	Morgan Stanley Capital Group Inc.	Idaho Power Company	Sierra Pacific Power	SFP
14	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	PacifiCorp East	NF
15	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
16	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	PacifiCorp East	NF
17	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
18	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	Avista	NF
19	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	Avista	SFP
20	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp East	NF
21	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp East	NF
22	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp East	NF
23	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp East	NF
24	Morgan Stanley Capital Group Inc.	PacifiCorp West	Sierra Pacific Power	NF
25	Nevada Power Company	PacifiCorp East	Sierra Pacific Power	NF
26	Nevada Power Company	Bonneville Power Administration	Sierra Pacific Power	NF
27	Nevada Power Company	Avista	Sierra Pacific Power	NF
28	Nevada Power Company	Avista	Sierra Pacific Power	SFP
29	PacifiCorp Inc.	PacifiCorp East	Avista	NF
30	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	NF
31	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	NF
32	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	SFP
33	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	NF
34	PacifiCorp Inc.	PacifiCorp East	Bonneville Power Administration	NF
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

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.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
7/8	LAGRANDE	M345		22,900	22,900	1
7/8	LOLO	BORA		23,234	23,234	2
7/8	LOLO	BORA		3,010	3,010	3
7/8	LOLO	BRDY		230	230	4
7/8	LOLO	M345		184,155	184,155	5
7/8	LOLO	M345		34,366	34,366	6
7/8	LYPK	BORA		22,839	22,839	7
7/8	LYPK	BORA		22,324	22,324	8
7/8	LYPK	BPAT.NWMT		51	51	9
7/8	LYPK	BRDY		416	416	10
7/8	LYPK	LOLO		110	110	11
7/8	LYPK	M345		23,710	23,710	12
7/8	LYPK	M345		223,399	223,399	13
7/8	M345	BORA		2,055	2,055	14
7/8	M345	BPAT.NWMT		172	172	15
7/8	M345	BRDY		75	75	16
7/8	M345	LAGRANDE		1,445	1,445	17
7/8	M345	LOLO		526	526	18
7/8	M345	LOLO		306	306	19
7/8	SMLK	BORA		339	339	20
7/8	SMLK	BRDY		65	65	21
7/8	WALLAWALLA	BORA		1,285	1,285	22
7/8	WALLAWALLA	BRDY		175	175	23
7/8	WALLAWALLA	M345		739	739	24
7/8	BRDY	M345		208	208	25
7/8	LAGRANDE	M345		50	50	26
7/8	LOLO	M345		14,435	14,435	27
7/8	LOLO	M345		10,900	10,900	28
7/8	BORA	LOLO		1,185	1,185	29
7/8	BRDY	BORA		808	808	30
7/8	BRDY	BRDY		1,279	1,279	31
7/8	BRDY	BRDY		2,531	2,531	32
7/8	BRDY	HURR		2,585	2,585	33
7/8	BRDY	LAGRANDE		3,716	3,716	34
			0	**6,319,072**	**6,319,072**	

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.

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 Classifi-cation (d)
1	PacifiCorp Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
2	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
3	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	SFP
4	PacifiCorp Inc.	PacifiCorp West	Bonneville Power Administration	NF
5	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	NF
6	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	SFP
7	PacifiCorp Inc.	Bonneville Power Administration	PacifiCorp East	NF
8	PacifiCorp Inc.	Bonneville Power Administration	PacifiCorp East	NF
9	PacifiCorp Inc.	Avista	PacifiCorp East	NF
10	PacifiCorp Inc.	Avista	PacifiCorp East	NF
11	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
12	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	SFP
13	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
14	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
15	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	SFP
16	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
17	Portland General Electric Company	PacifiCorp East	Bonneville Power Administration	NF
18	Portland General Electric Company	Bonneville Power Administration	PacifiCorp East	NF
19	Portland General Electric Company	Bonneville Power Administration	Sierra Pacific Power	NF
20	Portland General Electric Company	Sierra Pacific Power	Bonneville Power Administration	NF
21	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
22	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	NF
23	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	NF
24	Powerex Corporation	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
25	Powerex Corporation	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
26	Powerex Corporation	PacifiCorp East	PacifiCorp East	NF
27	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
28	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
29	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	SFP
30	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
31	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
32	Powerex Corporation	PacifiCorp East	PacifiCorp East	NF
33	Powerex Corporation	PacifiCorp East	PacifiCorp East	SFP
34	Powerex Corporation	PacifiCorp East	PacifiCorp East	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

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.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
7/8	BRDY	MLCK		100	100	1
7/8	HURR	BORA		9,640	9,640	2
7/8	HURR	BORA		66,578	66,578	3
7/8	HURR	LAGRANDE		341	341	4
7/8	JEFF	BGSY		50	50	5
7/8	JEFF	BGSY		70	70	6
7/8	LAGRANDE	BORA		2,532	2,532	7
7/8	LAGRANDE	BRDY		8,702	8,702	8
7/8	LOLO	BORA		330	330	9
7/8	LOLO	BRDY		4,317	4,317	10
7/8	SMLK	BORA		66,107	66,107	11
7/8	SMLK	BORA		48,505	48,505	12
7/8	SMLK	BRDY		5,070	5,070	13
7/8	WALLAWALLA	BORA		81,394	81,394	14
7/8	WALLAWALLA	BORA		126,597	126,597	15
7/8	WALLAWALLA	BRDY		347	347	16
7/8	BRDY	LAGRANDE		3,148	3,148	17
7/8	LAGRANDE	BORA		90	90	18
7/8	LAGRANDE	M345		100	100	19
7/8	M345	LAGRANDE		100	100	20
7/8	BORA	M345		100	100	21
7/8	BPAT.NWMT	BORA		306	306	22
7/8	BPAT.NWMT	BRDY		436	436	23
7/8	BPAT.NWMT	M345		2,695	2,695	24
7/8	BPAT.NWMT	M345		15,008	15,008	25
7/8	BRDY	BORA		251	251	26
7/8	BRDY	LAGRANDE		152	152	27
7/8	BRDY	M345		1,974	1,974	28
7/8	BRDY	M345		1,370	1,370	29
7/8	HURR	BORA		64	64	30
7/8	JBSN	M345		77	77	31
7/8	JEFF	BORA		1,994	1,994	32
7/8	JEFF	BORA		320	320	33
7/8	JEFF	BRDY		330	330	34
			0	**6,319,072**	**6,319,072**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

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 Classifi-cation (d)
1	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
2	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	SFP
3	Powerex Corporation	Bonneville Power Administration	PacifiCorp East	NF
4	Powerex Corporation	Bonneville Power Administration	PacifiCorp East	NF
5	Powerex Corporation	Bonneville Power Administration	Sierra Pacific Power	NF
6	Powerex Corporation	Avista	PacifiCorp East	NF
7	Powerex Corporation	Avista	PacifiCorp East	NF
8	Powerex Corporation	Avista	Sierra Pacific Power	NF
9	Powerex Corporation	Sierra Pacific Power	PacifiCorp East	NF
10	Powerex Corporation	Sierra Pacific Power	PacifiCorp East	NF
11	Powerex Corporation	Sierra Pacific Power	Bonneville Power Administration	NF
12	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
13	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
14	Powerex Corporation	PacifiCorp West	Sierra Pacific Power	NF
15	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
16	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
17	Powerex Corporation	PacifiCorp West	Sierra Pacific Power	NF
18	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	NF
19	Shell Energy North America (US), L.P.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
20	Shell Energy North America (US), L.P.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
21	Shell Energy North America (US), L.P.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
22	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	NF
23	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	NF
24	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	SFP
25	Shell Energy North America (US), L.P.	Idaho Power Company	Bonneville Power Administration	NF
26	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp East	NF
27	Shell Energy North America (US), L.P.	Bonneville Power Administration	Sierra Pacific Power	NF
28	Shell Energy North America (US), L.P.	Avista	PacifiCorp East	NF
29	Shell Energy North America (US), L.P.	Avista	PacifiCorp East	SFP
30	Shell Energy North America (US), L.P.	Avista	Sierra Pacific Power	NF
31	Shell Energy North America (US), L.P.	Avista	Sierra Pacific Power	SFP
32	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	NF
33	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp East	NF
34	Shell Energy North America (US), L.P.	Sierra Pacific Power	Bonneville Power Administration	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

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.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
7/8	JEFF	M345		6,597	6,597	1
7/8	JEFF	M345		1,800	1,800	2
7/8	LAGRANDE	BORA		10,216	10,216	3
7/8	LAGRANDE	BRDY		2,985	2,985	4
7/8	LAGRANDE	M345		33,957	33,957	5
7/8	LOLO	BORA		682	682	6
7/8	LOLO	BRDY		2,310	2,310	7
7/8	LOLO	M345		795	795	8
7/8	M345	BORA		436	436	9
7/8	M345	BRDY		13	13	10
7/8	M345	LAGRANDE		20	20	11
7/8	SMLK	BORA		17,185	17,185	12
7/8	SMLK	BRDY		1,729	1,729	13
7/8	SMLK	M345		2,359	2,359	14
7/8	WALLAWALLA	BORA		1,883	1,883	15
7/8	WALLAWALLA	BRDY		1,641	1,641	16
7/8	WALLAWALLA	M345		390	390	17
7/8	BORA	M345		630	630	18
7/8	BPAT.NWMT	BRDY		139	139	19
7/8	BPAT.NWMT	M345		4,221	4,221	20
7/8	BRDY	BPAT.NWMT		961	961	21
7/8	BRDY	LAGRANDE		1,077	1,077	22
7/8	BRDY	M345		19,939	19,939	23
7/8	BRDY	M345		6,208	6,208	24
7/8	IPCOGEN	LAGRANDE		734	734	25
7/8	LAGRANDE	BRDY		2,809	2,809	26
7/8	LAGRANDE	M345		65,438	65,438	27
7/8	LOLO	BRDY		2,228	2,228	28
7/8	LOLO	BRDY		224	224	29
7/8	LOLO	M345		28,695	28,695	30
7/8	LOLO	M345		6,397	6,397	31
7/8	LYPK	BRDY		288	288	32
7/8	M345	BRDY		151	151	33
7/8	M345	LAGRANDE		1,825	1,825	34
			0	**6,319,072**	**6,319,072**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

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)
1	Shell Energy North America (US), L.P.	PacifiCorp West	PacifiCorp East	NF
2	Shell Energy North America (US), L.P.	PacifiCorp West	PacifiCorp East	NF
3	Shell Energy North America (US), L.P.	PacifiCorp West	PacifiCorp East	SFP
4	Shell Energy North America (US), L.P.	PacifiCorp West	Sierra Pacific Power	NF
5	Shell Energy North America (US), L.P.	PacifiCorp West	Sierra Pacific Power	SFP
6	Shell Energy North America (US), L.P.	PacifiCorp West	PacifiCorp East	NF
7	Shell Energy North America (US), L.P.	PacifiCorp West	Sierra Pacific Power	NF
8	Talen Energy Marketing, LLC	PacifiCorp East	Idaho Power Company	NF
9	Talen Energy Marketing, LLC	PacifiCorp East	Bonneville Power Administration	NF
10	Talen Energy Marketing, LLC	Sierra Pacific Power	Idaho Power Company	NF
11	Tenaska Power Services Co.	PacifiCorp East	Bonneville Power Administration	NF
12	Tenaska Power Services Co.	PacifiCorp East	PacifiCorp East	NF
13	Tenaska Power Services Co.	Bonneville Power Administration	PacifiCorp East	NF
14	The Energy Authority, Inc.	PacifiCorp East	Bonneville Power Administration	NF
15	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
16	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
17	The Energy Authority, Inc.	Bonneville Power Administration	PacifiCorp East	NF
18	The Energy Authority, Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
19	The Energy Authority, Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
20	The Energy Authority, Inc.	PacifiCorp West	PacifiCorp East	NF
21	The Energy Authority, Inc.	PacifiCorp West	PacifiCorp East	NF
22	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Bonneville Power Administration	NF
23	Transalta Energy Marketing (U.S.) Inc.	Bonneville Power Administration	PacifiCorp East	NF
24	Transalta Energy Marketing (U.S.) Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
25	Transalta Energy Marketing (U.S.) Inc.	Avista	PacifiCorp East	NF
26	Transalta Energy Marketing (U.S.) Inc.	Avista	Sierra Pacific Power	NF
27	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
28	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
29	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp West	PacifiCorp East	NF
30	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp West	Sierra Pacific Power	NF
31	Utah Associated Municipal Power	PacifiCorp East	Sierra Pacific Power	NF
32				
33				
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

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.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
7/8	SMLK	BORA		704	704	1
7/8	SMLK	BRDY		15,037	15,037	2
7/8	SMLK	BRDY		1,192	1,192	3
7/8	SMLK	M345		19,483	19,483	4
7/8	SMLK	M345		3,274	3,274	5
7/8	WALLAWALLA	BRDY		2,921	2,921	6
7/8	WALLAWALLA	M345		3,265	3,265	7
7/8	BRDY	IPCO		11	11	8
7/8	BRDY	LAGRANDE		1,664	1,664	9
7/8	M345	IPCO		64	64	10
7/8	BRDY	LAGRANDE		127	127	11
7/8	JEFF	BRDY		65	65	12
7/8	LAGRANDE	BRDY		385	385	13
7/8	BORA	LAGRANDE		5	5	14
7/8	BPAT.NWMT	BRDY		144	144	15
7/8	BPAT.NWMT	M345		111	111	16
7/8	LAGRANDE	BRDY		1,223	1,223	17
7/8	LAGRANDE	M345		531	531	18
7/8	M345	LAGRANDE		796	796	19
7/8	SMLK	BORA		449	449	20
7/8	SMLK	BRDY		50	50	21
7/8	BORA	LAGRANDE		753	753	22
7/8	LAGRANDE	BORA		4,316	4,316	23
7/8	LAGRANDE	M345		185	185	24
7/8	LOLO	BORA		413	413	25
7/8	LOLO	M345		50	50	26
7/8	M345	BPAT.NWMT		150	150	27
7/8	M345	LAGRANDE		498	498	28
7/8	SMLK	BORA		4,267	4,267	29
7/8	SMLK	M345		50	50	30
7/8	BORA	M345		1,198	1,198	31
						32
						33
						34
			0	**6,319,072**	**6,319,072**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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 (11011) 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.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
1,676,396	200,287		1,876,683	1
1,603,473	56,273		1,659,746	2
6,247,662	463,643		6,711,305	3
11,016	953		11,969	4
	15,240		15,240	5
54,752			54,752	6
	140,325		140,325	7
	2,598		2,598	8
	4,113		4,113	9
	9,158		9,158	10
				11
	1,223,760		1,223,760	12
	1,223,760		1,223,760	13
	1,652,729		1,652,729	14
	5,772,577		5,772,577	15
	4,790,520		4,790,520	16
	2,419,213		2,419,213	17
				18
	40		40	19
	67,832		67,832	20
	92		92	21
	11,247		11,247	22
	101,677		101,677	23
	4,468		4,468	24
	8		8	25
	2,811		2,811	26
	18,009		18,009	27
	129		129	28
	353		353	29
	376		376	30
	227		227	31
	17,527		17,527	32
	18,220		18,220	33
	1,767		1,767	34
9,593,299	**21,897,498**	**0**	**31,490,797**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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 (11011) 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.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	4,861		4,861	1
	14,229		14,229	2
	3,583		3,583	3
	75		75	4
	5,145		5,145	5
	13,657		13,657	6
	43		43	7
	38,856		38,856	8
	22,072		22,072	9
	234		234	10
	34,949		34,949	11
	17,890		17,890	12
	739		739	13
	94		94	14
	387		387	15
	64		64	16
	31		31	17
	4,313		4,313	18
	10,886		10,886	19
	1,797		1,797	20
	44		44	21
	9,633		9,633	22
	47,414		47,414	23
	55,892		55,892	24
	1,201		1,201	25
	267		267	26
	1,532		1,532	27
	16,246		16,246	28
	100		100	29
	5,039		5,039	30
	82,898		82,898	31
	83		83	32
	11,536		11,536	33
	716		716	34
9,593,299	**21,897,498**	**0**	**31,490,797**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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 (11011) 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.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	28,672		28,672	1
	29,090		29,090	2
	3,769		3,769	3
	288		288	4
	230,570		230,570	5
	43,028		43,028	6
	28,595		28,595	7
	27,951		27,951	8
	64		64	9
	521		521	10
	138		138	11
	29,686		29,686	12
	279,705		279,705	13
	2,573		2,573	14
	215		215	15
	94		94	16
	1,809		1,809	17
	659		659	18
	383		383	19
	424		424	20
	81		81	21
	1,609		1,609	22
	219		219	23
	925		925	24
	778		778	25
	187		187	26
	53,985		53,985	27
	40,765		40,765	28
	3,268		3,268	29
	2,229		2,229	30
	3,528		3,528	31
	6,981		6,981	32
	7,130		7,130	33
	10,249		10,249	34
9,593,299	**21,897,498**	**0**	**31,490,797**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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 (11011) 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.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	276		276	1
	26,588		26,588	2
	183,630		183,630	3
	941		941	4
	138		138	5
	193		193	6
	6,984		6,984	7
	24,001		24,001	8
	910		910	9
	11,907		11,907	10
	182,331		182,331	11
	133,782		133,782	12
	13,984		13,984	13
	224,494		224,494	14
	349,169		349,169	15
	957		957	16
	14,915		14,915	17
	426		426	18
	474		474	19
	474		474	20
	440		440	21
	1,347		1,347	22
	1,919		1,919	23
	11,862		11,862	24
	66,055		66,055	25
	1,105		1,105	26
	669		669	27
	8,688		8,688	28
	6,030		6,030	29
	282		282	30
	339		339	31
	8,776		8,776	32
	1,408		1,408	33
	1,452		1,452	34
9,593,299	**21,897,498**	**0**	**31,490,797**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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 (11011) 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.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	29,036		29,036	1
	7,922		7,922	2
	44,964		44,964	3
	13,138		13,138	4
	149,457		149,457	5
	3,002		3,002	6
	10,167		10,167	7
	3,499		3,499	8
	1,919		1,919	9
	57		57	10
	88		88	11
	75,637		75,637	12
	7,610		7,610	13
	10,383		10,383	14
	8,288		8,288	15
	7,223		7,223	16
	1,717		1,717	17
	2,338		2,338	18
	516		516	19
	15,667		15,667	20
	3,567		3,567	21
	3,997		3,997	22
	74,008		74,008	23
	23,042		23,042	24
	2,724		2,724	25
	10,426		10,426	26
	242,886		242,886	27
	8,270		8,270	28
	831		831	29
	106,507		106,507	30
	23,744		23,744	31
	1,069		1,069	32
	560		560	33
	6,774		6,774	34
9,593,299	**21,897,498**	**0**	**31,490,797**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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 (11011) 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.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	2,613		2,613	1
	55,813		55,813	2
	4,424		4,424	3
	72,315		72,315	4
	12,151		12,151	5
	10,842		10,842	6
	12,118		12,118	7
	44		44	8
	6,710		6,710	9
	258		258	10
	531		531	11
	272		272	12
	1,611		1,611	13
	21		21	14
	608		608	15
	469		469	16
	5,168		5,168	17
	2,244		2,244	18
	3,364		3,364	19
	1,897		1,897	20
	211		211	21
	3,056		3,056	22
	17,513		17,513	23
	751		751	24
	1,676		1,676	25
	203		203	26
	609		609	27
	2,021		2,021	28
	17,314		17,314	29
	203		203	30
	5,883		5,883	31
				32
				33
				34
9,593,299	**21,897,498**	**0**	**31,490,797**	

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Schedule Page: 328 Line No.: 1 Column: a

The network service agreement between Idaho Power and the Bonneville Power Administration for the Oregon Trail Electric Cooperative expires September 30, 2028.

Schedule Page: 328 Line No.: 1 Column: e

9, Open Access Transmission Tariff, Schedule 9 Network Integration Transmission Service

Schedule Page: 328 Line No.: 1 Column: h

The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

Schedule Page: 328 Line No.: 2 Column: a

The network service agreement between Idaho Power and the Bonneville Power Administration for the United States Bureau of Reclamation expires December 31, 2023.

Schedule Page: 328 Line No.: 2 Column: h

The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

Schedule Page: 328 Line No.: 3 Column: a

The network service agreement between Idaho Power and the Bonneville Power Administration for the Priority Firm Customers expires September 30, 2028.

Schedule Page: 328 Line No.: 3 Column: h

The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

Schedule Page: 328 Line No.: 4 Column: a

The contract between Idaho Power and PacifiCorp - Imnaha expires on March 31, 2021.

Schedule Page: 328 Line No.: 4 Column: h

The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

Schedule Page: 328 Line No.: 5 Column: a

The contract between Idaho Power and the Milner Irrigation District expires December 31, 2017.

Schedule Page: 328 Line No.: 5 Column: e

Legacy, contract prior to the Open Access Transmission Tariff

Schedule Page: 328 Line No.: 6 Column: a

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.

Schedule Page: 328 Line No.: 7 Column: a

The agreement between Idaho Power and the City of Seattle expires December 31, 2017. City of Seattle has re-sold this transmission service request to Morgan Stanley Capital Group and Morgan Stanley is now responsible for payment.

Schedule Page: 328 Line No.: 7 Column: e

4, Open Access Transmission Tariff, Schedule 4 Energy Imbalance Service

Schedule Page: 328 Line No.: 8 Column: a

The agreement between Idaho Power and United Materials of Great Falls, Inc. has no expiration date and can be terminated by either party at any time.

Schedule Page: 328 Line No.: 8 Column: e

5/6, Open Access Transmission Tariff, Schedule 5/6 Operating Reserves

Schedule Page: 328 Line No.: 12 Column: e

7/8, Open Access Transmission Tariff, Schedule 7/8 Point-to-Point Transmission Service

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Arizona Public Service	NF				3,690		3,690
2	Arizona Public Service	OS					29	29
3	Arizona Public Service	OS					-18	-18
4	Avangrid Renewables	OS					-23,008	-23,008
5	Avista Corp-WWP Div	NF	4,337	4,337		27,592		27,592
6	Avista Corp-WWP Div	SFP	125,471	125,471		478,047		478,047
7	Avista Corp-WWP Div	OS					-121	-121
8	Benton County PUD	NF				250		250
9	Bonneville Power Admin	LFP	352,514	352,514		3,163,292		3,163,292
10	Bonneville Power Admin	SFP	2,516	2,516		14,336		14,336
11	Bonneville Power Admin	NF	6,634	6,634		32,995		32,995
12	Bonneville Power Admin	OS					632,309	632,309
13	Bonneville Power Admin	OS					25,725	25,725
14	Bonneville Power Admin	OS	190,297	190,297				
15	Bonneville Power Admin	OS	200	200				
16	Bonneville Power Admin	OS	26,055	26,055				
	TOTAL		740,642	740,642		5,237,419	317,702	5,555,121

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Power Admin	OS	3,144	3,144				
2	Bonneville Power Admin	OS	1,592	1,592				
3	Bonneville Power Admin	OS	4,582	4,582				
4	Exelon Generation Co	OS					-25,464	-25,464
5	NV Energy	SFP	271	271		5,000		5,000
6	NV Energy	OS					717	717
7	NV Energy	OS					-49,426	-49,426
8	NorthWestern Energy	SFP	1,783	1,783		11,429		11,429
9	NorthWestern Energy	NF	2,343	2,343		10,500		10,500
10	NorthWestern Energy	OS					1,095	1,095
11	PacifiCorp Inc.	LFP	2,896	2,896		969,534		969,534
12	PacifiCorp Inc.	NF	16,007	16,007		98,751		98,751
13	PacifiCorp Inc.	OS					47,205	47,205
14	PacifiCorp Inc.	OS					-1,400	-1,400
15	PacifiCorp Inc.	OS					-2,236	-2,236
16	PacifiCorp Inc.	OS					-11	-11
	TOTAL		740,642	740,642		5,237,419	317,702	5,555,121

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	PacifiCorp Inc.	OS					-489	-489
2	Powerex Corp.	OS					-190,557	-190,557
3	Puget Sound Energy, Inc	SFP				378,491		378,491
4	Seattle CIty Light	SFP				4,625		4,625
5	Shell Energy N. America	SFP				4,893		4,893
6	Shell Energy N. America	OS					-861	-861
7	Snohomish County PUD	SFP				31,582		31,582
8	Tacoma Power	SFP				2,412		2,412
9	TransAlta Energy U.S.	OS					-95,787	-95,787
10								
11								
12								
13								
14								
15								
16								
	TOTAL		740,642	740,642		5,237,419	317,702	5,555,121

Schedule Page: 332 Line No.: 2 Column: a
Ancillary Services
Schedule Page: 332 Line No.: 3 Column: a
Unreserved use penalty credit
Schedule Page: 332 Line No.: 4 Column: a
Transmission Resale
Schedule Page: 332 Line No.: 7 Column: a
Unreserved Use Penalty Credit
Schedule Page: 332 Line No.: 8 Column: a
BPAT is provider for capacity reassignment settled with Benton County PUD
Schedule Page: 332 Line No.: 9 Column: b
Contract Expiration Date 12/31/2021
Schedule Page: 332 Line No.: 12 Column: a
Ancillary Services
Schedule Page: 332 Line No.: 13 Column: a
Spinning/Supplemental Reserves
Schedule Page: 332 Line No.: 14 Column: a
BPAT is provider for capacity reassignment settled with Puget Sound Energy
Schedule Page: 332 Line No.: 15 Column: a
BPAT is provider for capacity reassignment settled with Benton County
Schedule Page: 332 Line No.: 16 Column: a
BPAT is provider for capacity reassignment settled with Snohomish County PUD

Schedule Page: 332.1 Line No.: 1 Column: a
BPAT is provider for capacity reassignment settled with Seattle City Light
Schedule Page: 332.1 Line No.: 2 Column: a
BPAT is provider for capacity reassignment settled with Tacoma Power.
Schedule Page: 332.1 Line No.: 3 Column: a
BPAT is provider for capacity reassignment settled with Shell Energy.
Schedule Page: 332.1 Line No.: 4 Column: a
Resale Transmission
Schedule Page: 332.1 Line No.: 6 Column: a
Ancillary Services
Schedule Page: 332.1 Line No.: 7 Column: a
Refunded PTP transmission for 1/9/15 - 4/9/16 due to 155 FERC P61,249 (2016)
Schedule Page: 332.1 Line No.: 10 Column: a
Ancillary Services
Schedule Page: 332.1 Line No.: 11 Column: b
Contract Expiration Date 05/31/2019
Schedule Page: 332.1 Line No.: 13 Column: a
Ancillary Services
Schedule Page: 332.1 Line No.: 14 Column: a
Resale Transmission
Schedule Page: 332.1 Line No.: 15 Column: a
PTP 2015 true-up
Schedule Page: 332.1 Line No.: 16 Column: a
Unreserved use penalty credit
Schedule Page: 332.2 Line No.: 1 Column: a
PTP 2014 true-up
Schedule Page: 332.2 Line No.: 2 Column: a
Resale Transmission
Schedule Page: 332.2 Line No.: 3 Column: a
BPAT is provider for capacity reassignment settled with Puget Sound Energy
Schedule Page: 332.2 Line No.: 4 Column: a

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BPAT is provider for capacity reassignment settled with Seattle City Light

Schedule Page: 332.2 Line No.: 5 Column: a

BPAT is provider for capacity reassignment settled with Shell Energy

Schedule Page: 332.2 Line No.: 6 Column: a

Resale Transmission

Schedule Page: 332.2 Line No.: 7 Column: a

BPAT is provider for capacity reassignment settled with Snohomish County PUD

Schedule Page: 332.2 Line No.: 8 Column: a

BPAT is provider for capacity reassignment settled with Tacoma Power

Schedule Page: 332.2 Line No.: 9 Column: a

Resale Transmission

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	516,427
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,652,922
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	126,771
6		
7	Director Fees and Expenses:	
8	Christine King	91,305
9	Dennis Johnson	69,959
10	J Lamont Keen	64,025
11	Judith Johansen	77,647
12	Richard Dahl	91,112
13	Richard Navarro	76,166
14	Robert Tintsman	177,685
15	Ronald Jibson	71,144
16	Thomas Carlile	75,845
17	Director travel and lodging	22,099
18		
19	Corporate Memberships and Subscriptions:	
20	Associated Taxpayers of Idaho	26,000
21	Business Plus	5,000
22	Idaho Association of Commerce & Industry	15,000
23	Idaho Technology Council	12,350
24	National Association of Directors	7,125
25	National Hydropower Association	35,860
26	North American Energy Standard	7,000
27	Northwest Power Pool	158,932
28	Pacific NW Utilities	42,747
29	SNL Financial Unlimited Subscription	25,931
30	Western Energy Coordinating Council	-21,979
31	Western Energy Institute	30,988
32	Misc Memberships Under $2,000	8,286
33		
34	Chambers of Commerce & Other Civic Organizations	85,875
35		
36		
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44		
45		
46	TOTAL	3,552,222

Schedule Page: 335 Line No.: 4 Column: b

Recipient	Purpose		Amount
American Stock Transfer & Trust	Mgmt Services	$	69,353
Bloomberg Finance LP	Misc Expense		11,299
Broadridge Financial Solutions	Misc Expense		47,512
Deutsche Bank	Broker Fees		30,000
E Source	Mgmt Services		41,499
Moody's Analytics	Mgmt Services		33,708
NASDAQ Corp Solutions	Mgmt Services		91,616
New York Stock Exchange	Listing Services		51,917
Payroll Related Expenses	Misc Expense		249,271
PR Newswire	Misc Expense		15,662
Rivel Research Group	Mgmt Services		15,840
Stock Based Compensation	Misc Expense		890,845
Wells Fargo Shareowner Services	Mgmt Services		104,400

		$	1,652,922
			=======

Schedule Page: 335 Line No.: 5 Column: b

Recipient	Purpose		Amount
Bank of New York	Revenue Bonds	$	12,925
Inspirus, LLC.	Employee Engagement		54,848
Investis, Inc.	Website Design		12,637
Payroll Related Expense	Misc Expense		17,660
Miscellaneous under $5,000	Misc Expense		28,701

		$	126,771
			======

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			6,649,455		6,649,455
2	Steam Production Plant	26,985,885	720,272			27,706,157
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	14,955,319				14,955,319
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	16,492,282				16,492,282
7	Transmission Plant	22,117,697				22,117,697
8	Distribution Plant	43,603,291				43,603,291
9	Regional Transmission and Market Operation					
10	General Plant	10,894,110				10,894,110
11	Common Plant-Electric					
12	TOTAL	135,048,584	720,272	6,649,455		142,418,311

B. Basis for Amortization Charges

Acct 404	Balance 1/1/2016	2016 Amortization	Balance 12/31/2016	Remaining Months
(1)	24,000	12,000	12,000	12
(2)	9,794,550	537,114	9,257,436	-
(3)	5,062,565	189,129	4,873,436	309
(4)	13,191,811	5,592,337	9,768,866	-
(5)	3,460,098	287,899	3,172,199	132
(6)	193,795	8,026	185,769	48
(7)	878,552	22,950	1,128,967	-
	----------------	----------------	----------------	
Total	32,605,372	6,649,455	28,398,674	

(1) Shoshone-Bannock Tribe License & Use Agreement(Termination date 12/31/23).
(2) Middle Snake Relicensing Costs (Amortized over a 30 year license period; licenses expire 07/31/34 and 02/28/35).
(3) Swan Falls Relicensing Costs (Amortized over a 30 year license period).
(4) Computer Software packages (Amortized over a 60 month period from date of purchase).
(5) Shoshone-Bannock Right of Way (Termination date 12/31/27).
(6) Boardman Retrofit Tech Analysis (Scheduled decommission date 12/31/20).
(7) FERC License Compliance Costs (Termination date will be expiration date of the applicable FERC Licenses) .

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	310.20	649	75.00		3.70	R4.0	20.20
13	311.00	151,561	100.00	-10.00	1.82	S1.0	21.30
14	312.10	193,075	60.00	-5.00	1.41	R3.0	21.80
15	312.20	560,728	60.00	-5.00	2.78	R1.5	20.90
16	312.30	4,341	25.00	20.00	2.26	R3.0	7.90
17	314.00	165,722	45.00	-5.00	3.27	S1.0	19.40
18	315.00	72,133	60.00		1.44	S1.5	19.80
19	316.00	13,558	45.00	-5.00	3.78	R0.5	19.00
20	316.10	152	12.00	15.00	8.19	L2.0	6.30
21	316.40	250	12.00	15.00	0.68	L2.0	7.90
22	316.50	366	12.00	15.00	3.19	L2.0	5.10
23	316.60	106	20.00	15.00	4.39	L2.0	18.00
24	316.70	80	20.00	15.00	2.09	L2.0	14.40
25	316.80	2,978	20.00	30.00	3.50	O1.0	16.60
26	316.90	14	35.00	15.00	2.45	S1.0	34.70
27	317.00	15,312					
28	Subtotal Steam	1,181,025					
29	331.00	179,023	105.00	-25.00	2.39	R2.5	33.00
30	332.10	19,461	95.00	-20.00	1.31	S4.0	39.80
31	332.20	246,829	95.00	-20.00	1.65	S4.0	35.60
32	332.30	5,472			1.44	Square	49.10
33	333.00	241,657	80.00	-5.00	1.74	R3.0	32.60
34	334.00	60,377	50.00	-5.00	2.77	R1.5	26.10
35	335.00	23,707	95.00		2.26	R2.0	28.10
36	335.10	88	15.00		7.94	Square	6.50
37	335.20	407	20.00		5.61	Square	5.30
38	335.30	313	5.00		14.22	Square	3.30
39	336.00	10,843	75.00		2.48	R3.0	21.40
40	Subtotal Hydro	788,177					
41	341.00	143,168			2.92	Square	27.20
42	342.00	10,452	50.00		2.90	S2.5	28.50
43	343.00	229,874	40.00		3.32	S1.5	25.90
44	344.00	66,532	45.00		2.64	S2.0	26.80
45	345.00	91,147	50.00		3.39	S1.5	22.60
46	346.00	6,240	35.00		3.35	R2.5	24.50
47	Subtotal Other	547,413					
48	350.20	32,571	70.00		1.39	R3.0	58.50
49	350.22	187	30.00		3.33		
50	352.00	79,540	65.00	-35.00	1.84	R3.0	53.70

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	353.00	411,289	50.00	-5.00	1.90	R1.5	40.70
13	354.00	198,103	65.00	-15.00	1.70	S3.0	50.80
14	355.00	174,170	60.00	-70.00	2.77	R2.0	43.60
15	355.10	1,003	10.00		10.00		
16	356.00	219,215	65.00	-40.00	2.25	R2.0	48.50
17	359.00	390	65.00		0.79	R2.5	24.00
18	Subtotal Transmission	1,116,468					
19	360.22	730	30.00		3.33		30.00
20	361.00	36,984	65.00	-40.00	2.14	R2.5	53.30
21	362.00	222,357	50.00	-5.00	2.00	R1.0	40.20
22	364.00	252,409	44.00	-45.00	3.08	R1.5	31.30
23	364.10	3,750	12.00		8.34		
24	365.00	131,275	45.00	-35.00	2.98	R0.5	33.60
25	366.00	49,795	60.00	-20.00	1.95	R2.0	48.40
26	367.00	243,650	46.00	-15.00	2.26	R2.0	35.30
27	368.00	536,551	35.00	-3.00	2.58	R1.0	27.00
28	369.00	59,471	40.00	-40.00	2.55	R2.0	29.50
29	370.00	16,367	22.00	1.00	3.46	O1.0	17.50
30	370.10	70,892	15.00		6.96	S2.5	13.10
31	371.10		12.00	-2.00		S4.0	9.00
32	371.20	3,017	17.00	-2.00	1.51	R1.5	14.70
33	373.20	4,501	30.00	-25.00	2.41	R1.0	20.60
34	374.00	164					
35	Subtotal Distribution	1,631,913					
36	390.11	30,295	100.00	-5.00	2.58	S0.5	28.80
37	390.12	88,155	55.00	-5.00	1.90	S0.5	44.30
38	390.20		35.00		2.15	S3.0	25.70
39	391.10	14,885	20.00		2.88	Square	12.90
40	391.20	26,027	5.00		11.12	Square	3.20
41	391.21	8,172	8.00		11.22	L2.0	5.70
42	392.10	917	12.00	15.00	7.50	L2.0	8.90
43	392.30	4,563	10.00	50.00	1.73	S2.5	3.40
44	392.40	23,745	12.00	15.00	7.36	L2.0	6.80
45	392.50	1,119	12.00	15.00	3.53	L2.0	9.00
46	392.60	39,162	20.00	15.00	4.14	L2.0	13.40
47	392.70	6,845	20.00	15.00	3.21	L2.0	12.50
48	392.90	5,077	35.00	15.00	2.10	S1.0	24.30
49	393.00	2,620	25.00		3.30	Square	19.40
50	394.00	8,666	20.00		4.13	Square	13.30

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	395.00	13,022	20.00		4.29	Square	12.10
13	396.00	15,085	20.00	30.00	1.66	O1.0	17.60
14	397.10	4,145	15.00		4.25	Square	8.30
15	397.20	29,946	15.00		5.38	Square	9.80
16	397.30	3,473	15.00		5.31	Square	8.00
17	397.40	19,029	10.00		7.90	Square	6.50
18	398.00	6,571	15.00		5.20	Square	10.60
19	Subtotal General	351,519					
20	Total Plant	5,616,515					
21							
22							
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Schedule Page: 336 Line No.: 28 Column: a

Steam, hydro, and other production depreciation and amortization of certain electric plant is maintained by plant location. Effective April 1, 1993 the forecast life span method of life analysis using an interim retirement rate was utilized to develop all production plant rates. Rates, service lives, net salvage and remaining lives indicated are on a composite basis. An average plant balance was used in computing these rates by FERC account. Effective April 1, 1993, all depreciable plant is being depreciated using the straight-line remaining life method.

Schedule Page: 336 Line No.: 40 Column: a

Steam, hydro, and other production depreciation and amortization of certain electric plant is maintained by plant location. Effective April 1, 1993 the forecast life span method of life analysis using an interim retirement rate was utilized to develop all production plant rates. Rates, service lives, net salvage and remaining lives indicated are on a composite basis. An average plant balance was used in computing these rates by FERC account. Effective April 1, 1993, all depreciable plant is being depreciated using the straight-line remaining life method.

Schedule Page: 336 Line No.: 47 Column: a

Steam, hydro, and other production depreciation and amortization of certain electric plant is maintained by plant location. Effective April 1, 1993 the forecast life span method of life analysis using an interim retirement rate was utilized to develop all production plant rates. Rates, service lives, net salvage and remaining lives indicated are on a composite basis. An average plant balance was used in computing these rates by FERC account. Effective April 1, 1993, all depreciable plant is being depreciated using the straight-line remaining life method.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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.

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 Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission:				
2	Annual admin charges assessed by FERC	3,289,462		3,289,462	
3					
4	General Regulatory Expenses and				
5	Various other Dockets		23,538	23,538	
6					
7	Oregon Hydro - Fees Amortization	163,353		163,353	
8					
9	Regulatory Commission Expenses - Idaho				
10	Rate Case - Misc expenses		193,188	193,188	
11					
12	Regulatory Commission Expenses - Oregon				
13	Rate Case - Misc expenses		825	825	
14	General Regulatory		136,981	136,981	
15	Other OPUC expenses		11,049	11,049	
16					
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45					
46	TOTAL	3,452,815	365,581	3,818,396	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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 column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	3,289,462					2
							3
							4
Electric	928	23,538					5
							6
Electric	928	163,353					7
							8
							9
Electric	928	684		928203	192,504	80,210	10
							11
							12
Electric	928	825					13
Electric	928	136,981					14
Electric	928	11,049					15
							16
							17
							18
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							45
		3,625,892			192,504	80,210	46

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 & 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 & 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 & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	Idaho Power did not incur any Research and	
2	Development expenditures in 2016.	
3		
4		
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & 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 & 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 & 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 &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.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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	21,637,003		
4	Transmission	6,570,443		
5	Regional Market			
6	Distribution	18,245,062		
7	Customer Accounts	9,445,563		
8	Customer Service and Informational	5,338,448		
9	Sales			
10	Administrative and General	71,207,473		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	132,443,992		
12	Maintenance			
13	Production	4,501,996		
14	Transmission	3,042,252		
15	Regional Market			
16	Distribution	8,567,356		
17	Administrative and General	1,093,877		
18	TOTAL Maintenance (Total of lines 13 thru 17)	17,205,481		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	26,138,999		
21	Transmission (Enter Total of lines 4 and 14)	9,612,695		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	26,812,418		
24	Customer Accounts (Transcribe from line 7)	9,445,563		
25	Customer Service and Informational (Transcribe from line 8)	5,338,448		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	72,301,350		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	149,649,473		149,649,473
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	149,649,473		149,649,473
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant			
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)			
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense	4,767,872		4,767,872
79	Other Clearing Accounts	3,462,128		3,462,128
80	Construction Work in Progress	57,862,213		57,862,213
81	Other Work in Progress	3,330,273		3,330,273
82	Preliminary Survey and Invest	-930		-930
83	Other Accounts	4,721,481		4,721,481
84	Indirect Loading		46,731,443	46,731,443
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	74,143,037	46,731,443	74,143,037
96	TOTAL SALARIES AND WAGES	223,792,510	46,731,443	223,792,510

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Schedule Page: 354 Line No.: 84 Column: a

Amount reported is total amount of indirect loading. The loading is allocated to departments based on labor charges.

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), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch			660,996			
2	Reactive Supply and Voltage			20,360			
3	Regulation and Frequency Response				3,056,677	KW	299,401
4	Energy Imbalance				1,251	KWH	82,801
5	Operating Reserve - Spinning			13,422	4,110,746	KW	402,648
6	Operating Reserve - Supplement			12,303	4,110,746	KW	402,648
7	Other						
8	Total (Lines 1 thru 7)			707,081	11,279,420		1,187,498

Schedule Page: 398 Line No.: 1 Column: b

Idaho Power does not systematically record the number of units related to ancillary services purchased.

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.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	3,055	12	800	1,853	222	773		207	
2	February	3,094	3	800	2,016	221	773		84	
3	March	2,652	14	2100	1,328	175	773		376	
4	Total for Quarter 1				5,197	618	2,319		667	
5	April	2,707	23	1100	1,305	204	773		425	
6	May	3,193	13	2200	1,762	253	773		405	
7	June	4,359	27	1900	2,916	365	773		305	
8	Total for Quarter 2				5,983	822	2,319		1,135	
9	July	4,327	28	2100	2,952	344	973		58	
10	August	4,314	15	1800	2,982	331	973		28	
11	September	3,688	1	2100	2,256	294	973		165	
12	Total for Quarter 3				8,190	969	2,919		251	
13	October	2,865	19	800	1,585	171	973		136	
14	November	3,062	30	1900	1,661	189	973		239	
15	December	3,555	18	2000	2,034	233	973		315	
16	Total for Quarter 4				5,280	593	2,919		690	
17	Total Year to Date/Year				24,650	3,002	10,476		2,743	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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)	14,195,750
3	Steam	4,045,173			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	6,407,999			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,185,879
7	Other	1,721,540			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	12,174,712	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	4,330,800	27	Total Energy Losses	1,181,741
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	16,563,370
12	Received	234,717			
13	Delivered	181,766			
14	Net Exchanges (Line 12 minus line 13)	52,951			
15	Transmission For Other (Wheeling)				
16	Received	6,319,072			
17	Delivered	6,314,165			
18	Net Transmission for Other (Line 16 minus line 17)	4,907			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	16,563,370			

Schedule Page: 401 Line No.: 17 Column: b

Page 329 column I differs from page 401 by 4,907 MWH, reported for Lucky Peak 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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).

NAME OF SYSTEM: IDAHO POWER COMPANY - SYSTEM LOAD

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	1,457,546	183,192	2,183	2	10 AM
30	February	1,241,728	142,613	2,110	2	8 AM
31	March	1,262,333	180,716	1,856	18	8 AM
32	April	1,128,524	52,857	1,983	21	6 PM
33	May	1,284,936	47,292	2,251	31	7 PM
34	June	1,626,701	6,491	3,299	28	7 PM
35	July	1,758,172	59,135	3,172	30	6 PM
36	August	1,691,699	57,739	3,032	2	7 PM
37	September	1,248,843	107,061	2,533	1	6 PM
38	October	1,148,790	108,560	1,759	17	8 PM
39	November	1,171,785	115,460	1,902	30	7 PM
40	December	1,542,313	124,762	2,409	19	9 AM
41	TOTAL	16,563,370	1,185,878			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Jim Bridger* (b)	Plant Name: *Boardman* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor Boiler	Conventional
3	Year Originally Constructed	1974	1980
4	Year Last Unit was Installed	1979	1980
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	770.50	64.20
6	Net Peak Demand on Plant - MW (60 minutes)	726	60
7	Plant Hours Connected to Load	8784	3952
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	3671656000	134253000
13	Cost of Plant: Land and Land Rights	509671	106610
14	Structures and Improvements	69929509	12627358
15	Equipment Costs	616689787	63694825
16	Asset Retirement Costs	9832782	5380764
17	Total Cost	696961749	81809557
18	Cost per KW of Installed Capacity (line 17/5) Including	904.5578	1274.2922
19	Production Expenses: Oper, Supv, & Engr	194683	446094
20	Fuel	122819957	3412551
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	5396104	687008
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	6168487	790829
27	Rents	206742	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	26858	73194
30	Maintenance of Structures	0	45008
31	Maintenance of Boiler (or reactor) Plant	8836949	165264
32	Maintenance of Electric Plant	2332824	1373692
33	Maintenance of Misc Steam (or Nuclear) Plant	6295983	50491
34	Total Production Expenses	152278587	7044131
35	Expenses per Net KWh	0.0415	0.0525

Line No.	Item (a)	(b)			(c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	2080695	7181	0	80208	871	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9098	140000	0	8576	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	54.148	74.919	0.000	31.383	72.611	0.000
41	Average Cost of Fuel per Unit Burned	58.653	82.024	0.000	41.595	73.116	0.000
42	Average Cost of Fuel Burned per Million BTU	3.200	13.950	0.000	2.425	12.542	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.033	0.000	0.000	0.025	0.000	0.000
44	Average BTU per KWh Net Generation	10400.000	0.000	0.000	10285.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: *Valmy* (d)	Plant Name: *Danskin* (e)	Plant Name: *Bennett Mountain* (f)	Line No.
Steam	Gas Turbine	Gas Turbine	1
Outdoor	Conventional	Conventional	2
1981	2001	2005	3
1985	2008	2005	4
283.50	270.90	172.80	5
262	292	190	6
4878	1208	662	7
0	261	164	8
0	0	0	9
0	0	0	10
0	7	5	11
239264000	198102000	103240000	12
1106140	402745	0	13
69004095	6049223	1688442	14
333118561	100471959	52050151	15
98338	0	0	16
403327134	106923927	53738593	17
1422.6707	394.6989	310.9872	18
518084	165577	4108	19
11456244	8436529	3610656	20
0	0	0	21
2888080	0	0	22
0	0	0	23
0	0	0	24
1466072	358307	371728	25
2137930	275907	116703	26
0	0	0	27
0	0	0	28
50	0	0	29
483113	201461	102460	30
5261132	9520	15798	31
1444059	277616	211424	32
88874	0	0	33
25743638	9724917	4432877	34
0.1076	0.0491	0.0429	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCF			MCF			37
120330	7480	0	2050748	0	0	1072868	0	0	38
9945	138778	0	1027	0	0	1027	0	0	39
0.000	64.976	0.000	4.114	0.000	0.000	3.365	0.000	0.000	40
90.993	65.204	0.000	4.114	0.000	0.000	3.365	0.000	0.000	41
4.575	11.187	0.000	3.710	0.000	0.000	2.990	0.000	0.000	42
0.048	0.000	0.000	0.043	0.000	0.000	0.035	0.000	0.000	43
10185.000	0.000	0.000	10631.000	0.000	0.000	10673.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Langley Gulch* (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine					
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional					
3	Year Originally Constructed	2012					
4	Year Last Unit was Installed	2012					
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	318.45			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	304			0		
7	Plant Hours Connected to Load	5443			0		
8	Net Continuous Plant Capability (Megawatts)	300			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	23			0		
12	Net Generation, Exclusive of Plant Use - KWh	1420178000			0		
13	Cost of Plant: Land and Land Rights	2287261			0		
14	Structures and Improvements	135418367			0		
15	Equipment Costs	250825980			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	388531608			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	1220.0710			0		
19	Production Expenses: Oper, Supv, & Engr	432090			0		
20	Fuel	29750594			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	3424534			0		
26	Misc Steam (or Nuclear) Power Expenses	306858			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	96896			0		
31	Maintenance of Boiler (or reactor) Plant	56641			0		
32	Maintenance of Electric Plant	2275652			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	36343265			0		
35	Expenses per Net KWh	0.0256			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas					
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF					
38	Quantity (Units) of Fuel Burned	9708637	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1027	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.064	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.064	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.810	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.021	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	7021.000	0.000	0.000	0.000	0.000	0.000

Schedule Page: 402 Line No.: 3 Column: b

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 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.

Schedule Page: 402 Line No.: 3 Column: c

This footnote applies to lines 3 and 4. The Boardman plant consists of one unit constructed jointly by Portland General Electric Company, Idaho Power Company, and Pacific Northwest Generating Company, with Idaho Power Company owning 10%. The unit was placed in commercial operation August 3, 1980.

Schedule Page: 403 Line No.: 3 Column: d

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 owning 1/2. Unit #1 was placed in commercial operation December 11, 1981 and Unit #2 May 21, 1985.

Schedule Page: 402 Line No.: 5 Column: b

This footnote applies to line 5 and lines 12 through 43. Information reflects Idaho Power Company's share as explained in note for line 3 page 402 column B.

Schedule Page: 402 Line No.: 5 Column: c

This footnote applies to line 5 and lines 12 through 43. Information reflects Idaho Power Company's share as explained in note on line 3 page 402 column C

Schedule Page: 403 Line No.: 5 Column: d

This footnote applies to line 5 and lines 12 through 43. Information reflects Idaho Power Company's share as explained in note for line 3 page 403 column D.

Schedule Page: 402 Line No.: 9 Column: b

This footnote applies to lines 9, 10, and 11. PacifiCorp as operator of the plant will report this information.

Schedule Page: 402 Line No.: 9 Column: c

This footnote applies to lines 9, 10, and 11. Portland General Electric Company, as operator will report this information.

Schedule Page: 403 Line No.: 9 Column: d

This footnote applies to lines 9, 10, and 11. Sierra Pacific Power, as operator of the plant, will report this information.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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.

Line No.	Item (a)	FERC Licensed Project No. 2736 Plant Name: American Falls (b)	FERC Licensed Project No. 1975 Plant Name: Bliss (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Outdoor
3	Year Originally Constructed	1978	1949
4	Year Last Unit was Installed	1978	1950
5	Total installed cap (Gen name plate Rating in MW)	92.30	75.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	101	50
7	Plant Hours Connect to Load	4,991	8,760
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	110	76
10	(b) Under the Most Adverse Oper Conditions	0	1
11	Average Number of Employees	4	4
12	Net Generation, Exclusive of Plant Use - Kwh	243,379,000	287,612,000
13	Cost of Plant		
14	Land and Land Rights	875,318	768,366
15	Structures and Improvements	11,970,406	1,204,436
16	Reservoirs, Dams, and Waterways	4,293,075	9,264,107
17	Equipment Costs	32,352,657	9,851,554
18	Roads, Railroads, and Bridges	839,276	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	50,330,732	21,574,940
21	Cost per KW of Installed Capacity (line 20 / 5)	545.2950	287.6659
22	Production Expenses		
23	Operation Supervision and Engineering	231,008	711,269
24	Water for Power	1,635,039	483,334
25	Hydraulic Expenses	157,440	823,619
26	Electric Expenses	45,475	64,113
27	Misc Hydraulic Power Generation Expenses	340,392	439,728
28	Rents	189	4,496
29	Maintenance Supervision and Engineering	10,010	9,126
30	Maintenance of Structures	152,678	27,108
31	Maintenance of Reservoirs, Dams, and Waterways	12,061	114,324
32	Maintenance of Electric Plant	323,002	212,224
33	Maintenance of Misc Hydraulic Plant	79,880	163,801
34	Total Production Expenses (total 23 thru 33)	2,987,174	3,053,142
35	Expenses per net KWh	0.0123	0.0106

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

FERC Licensed Project No. 1971 Plant Name: Brownlee (d)	FERC Licensed Project No. 2848 Plant Name: Cascade (e)	FERC Licensed Project No. 1971 Plant Name: Oxbow (f)	Line No.
Storage	Run-of-River	Storage	1
Outdoor	Outdoor	Outdoor	2
1958	1983	1961	3
1980	1984	1961	4
585.40	12.42	190.00	5
527	14	209	6
8,760	8,742	8,760	7
			8
747	15	221	9
220	1	202	10
8	2	6	11
2,013,477,000	42,248,000	900,918,000	12
			13
18,252,564	82,142	1,212,767	14
33,065,915	7,328,252	11,245,847	15
67,618,609	3,145,630	30,502,861	16
81,231,487	13,090,143	20,015,998	17
518,444	122,668	585,876	18
0	0	0	19
200,687,019	23,768,835	63,563,349	20
342.8203	1,913.7548	334.5439	21
			22
761,656	217,394	503,635	23
271,359	104,837	169,876	24
1,027,992	356,152	663,155	25
335,263	120,211	252,190	26
824,783	287,712	543,434	27
113,644	62	18,633	28
19,067	3,508	14,964	29
127,024	13,644	251,906	30
16,243	-10	16,802	31
281,651	61,939	129,815	32
485,943	91,999	308,498	33
4,264,625	1,257,448	2,872,908	34
0.0021	0.0298	0.0032	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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.

Line No.	Item (a)	FERC Licensed Project No. 1971 Plant Name: Hells Canyon (b)	FERC Licensed Project No. 2726 Plant Name: Malad (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Outdoor
3	Year Originally Constructed	1967	1948
4	Year Last Unit was Installed	1967	1948
5	Total installed cap (Gen name plate Rating in MW)	391.50	21.77
6	Net Peak Demand on Plant-Megawatts (60 minutes)	426	24
7	Plant Hours Connect to Load	8,760	8,659
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	445	25
10	(b) Under the Most Adverse Oper Conditions	137	21
11	Average Number of Employees	6	1
12	Net Generation, Exclusive of Plant Use - Kwh	1,792,718,000	116,384,000
13	Cost of Plant		
14	Land and Land Rights	1,880,381	205,376
15	Structures and Improvements	2,795,004	3,886,385
16	Reservoirs, Dams, and Waterways	53,033,657	6,283,406
17	Equipment Costs	19,945,556	15,331,362
18	Roads, Railroads, and Bridges	922,781	1,507,442
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	78,577,379	27,213,971
21	Cost per KW of Installed Capacity (line 20 / 5)	200.7085	1,250.0676
22	Production Expenses		
23	Operation Supervision and Engineering	430,489	166,977
24	Water for Power	162,406	717,775
25	Hydraulic Expenses	631,815	205,027
26	Electric Expenses	229,330	28,600
27	Misc Hydraulic Power Generation Expenses	516,261	166,478
28	Rents	30,994	0
29	Maintenance Supervision and Engineering	12,495	7,496
30	Maintenance of Structures	22,636	26,120
31	Maintenance of Reservoirs, Dams, and Waterways	159,047	136,148
32	Maintenance of Electric Plant	91,522	206,236
33	Maintenance of Misc Hydraulic Plant	361,299	56,510
34	Total Production Expenses (total 23 thru 33)	2,648,294	1,717,367
35	Expenses per net KWh	0.0015	0.0148

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

FERC Licensed Project No. 2055 Plant Name: C J Strike (d)	FERC Licensed Project No. 503 Plant Name: Swan Falls (e)	FERC Licensed Project No. 18 Plant Name: Twin Falls (f)	Line No.
Run-of-River	Run-of-River	Run-of-River	1
Outdoor	Conventional	Conventional	2
1952	1910	1935	3
1952	1994	1995	4
82.80	25.00	52.74	5
84	19	38	6
8,756	8,730	5,968	7
			8
91	24	53	9
84	14	50	10
5	4	3	11
376,793,000	112,684,000	39,449,000	12
			13
5,711,701	231,584	255,499	14
9,806,855	27,388,566	11,108,328	15
11,276,408	15,989,465	9,069,862	16
14,060,693	31,563,288	21,327,698	17
1,602,868	835,946	1,917,603	18
0	0	0	19
42,458,525	76,008,849	43,678,990	20
512.7841	3,040.3540	828.1947	21
			22
856,216	506,602	220,174	23
381,008	235,465	99,437	24
1,093,411	661,799	198,860	25
52,239	32,394	78,058	26
680,252	497,063	219,150	27
49,273	7,841	3,261	28
6,825	7,226	4,981	29
77,984	83,133	57,802	30
71,008	12,905	29,075	31
139,631	185,902	113,846	32
98,400	127,805	81,705	33
3,506,247	2,358,135	1,106,349	34
0.0093	0.0209	0.0280	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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.

Line No.	Item (a)	FERC Licensed Project No. 2777 Plant Name: Upper Salmon (b)	FERC Licensed Project No. 2778 Plant Name: Shoshone Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1937	1907
4	Year Last Unit was Installed	1947	1921
5	Total installed cap (Gen name plate Rating in MW)	34.50	12.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	35	13
7	Plant Hours Connect to Load	8,753	6,730
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	39	14
10	(b) Under the Most Adverse Oper Conditions	32	11
11	Average Number of Employees	3	2
12	Net Generation, Exclusive of Plant Use - Kwh	176,762,000	54,752,000
13	Cost of Plant		
14	Land and Land Rights	202,399	313,328
15	Structures and Improvements	2,456,980	1,253,635
16	Reservoirs, Dams, and Waterways	6,181,301	10,097,561
17	Equipment Costs	8,930,990	4,815,784
18	Roads, Railroads, and Bridges	29,359	51,383
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	17,801,029	16,531,691
21	Cost per KW of Installed Capacity (line 20 / 5)	515.9719	1,322.5353
22	Production Expenses		
23	Operation Supervision and Engineering	297,671	167,994
24	Water for Power	132,433	73,325
25	Hydraulic Expenses	356,912	110,579
26	Electric Expenses	152,070	33,636
27	Misc Hydraulic Power Generation Expenses	252,672	209,089
28	Rents	0	87
29	Maintenance Supervision and Engineering	5,355	2,721
30	Maintenance of Structures	69,785	25,947
31	Maintenance of Reservoirs, Dams, and Waterways	55,168	785
32	Maintenance of Electric Plant	69,086	56,964
33	Maintenance of Misc Hydraulic Plant	109,603	70,614
34	Total Production Expenses (total 23 thru 33)	1,500,755	751,741
35	Expenses per net KWh	0.0085	0.0137

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

FERC Licensed Project No. 1971 Plant Name: Common Facilities (d)	FERC Licensed Project No. 2061 Plant Name: Lower Salmon (e)	FERC Licensed Project No. 2899 Plant Name: Milner (f)	Line No.
	Run-of-River	Run-of-River	1
	Outdoor	Conventional	2
	1949	1992	3
	1949	1992	4
0.00	60.00	59.45	5
0	36	44	6
0	8,760	2,763	7
			8
0	64	61	9
0	60	1	10
0	5	2	11
0	190,509,000	27,473,000	12
			13
114,368	424,428	138,100	14
41,383,976	2,869,695	10,704,939	15
13,556,785	6,962,069	17,847,178	16
2,354,402	17,635,166	29,363,867	17
107,482	88,693	501,877	18
0	0	0	19
57,517,013	27,980,051	58,555,961	20
0.0000	466.3342	984.9615	21
			22
0	315,441	190,615	23
0	149,610	1,370,918	24
7,688,417	456,008	130,597	25
0	118,062	40,445	26
0	363,699	252,646	27
0	3,172	3,711	28
0	7,500	4,025	29
0	171,514	45,733	30
0	7,337	23,662	31
0	169,155	92,989	32
100,912	77,289	65,819	33
7,789,329	1,838,787	2,221,160	34
0.0000	0.0097	0.0808	35

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Schedule Page: 406 Line No.: 1 Column: b

American Falls generating capacity is dependent upon water releases controlled by the USBR.

Schedule Page: 406 Line No.: 1 Column: e

Cascade generating capacity is dependent upon water releases controlled by the USBR.

Schedule Page: 406 Line No.: 1 Column: f

Upstream storage in Brownlee Reservoir

Schedule Page: 406.1 Line No.: 1 Column: b

Upstream storage in Brownlee Reservoir

Schedule Page: 406.1 Line No.: 1 Column: c

Lower Malad maximum demand 15,000 Kw, Upper Malad maximum demand 9,000 Kw non-coincident.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydro:					
2	Clear Lakes	1937	2.50	3.9	16,538	3,529,671
3	Thousand Springs	1912	8.80	6.6	16,303	9,843,459
4						
5						
6	Internal Combustion:					
7	Salmon Diesel	1967	5.00	3.6	20	909,259
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 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.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
1,411,868	182,242		97,034			2
1,118,575	282,615		102,843			3
						4
						5
						6
181,852				Diesel		7
						8
						9
						10
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Schedule Page: 410 Line No.: 7 Column: a

Salmon units are classified as standby.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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.
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. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Borah	Midpoint	345.00	500.00	S Tower	62.35		1
2	Boardman	Slatt	500.00	500.00	S Tower	1.79		1
3	Summer lake	Hemingway	500.00	500.00	S Tower	0.08		1
4	Hemingway	Midpoint	500.00	500.00	S Tower	0.15		1
5	Summer Lake	Hemingway	500.00	500.00	S Tower	53.09		1
6	Hemingway	Midpoint	500.00	500.00	S Tower	47.83		1
7								
8	Jim Bridger	Goshen	345.00	345.00	S Tower	66.13		1
9	State Line	Midpoint	345.00	345.00	S Tower	76.06		2
10	Kinport	Borah	345.00	345.00	S Tower	19.84		1
11	Jim Bridger	Populus	345.00	345.00	S Tower	61.28		1
12	Populus	Kinport	345.00	345.00	S Tower	7.42		1
13	Jim Bridger	Populus	345.00	345.00	S Tower	61.42		1
14	Populus	Borah	345.00	345.00	S Tower	9.05		1
15	Goshen	Kinport	345.00	345.00	S Tower	7.49		1
16	Midpoint	Borah #1	345.00	345.00	H Wood	51.07		1
17	Midpoint	Borah #2	345.00	345.00	H Wood	50.01		2
18	Adelaide Tap	Adelaide	345.00	345.00	H Wood	1.72		2
19								
20	Quartz	LaGrande	230.00	230.00	H Wood	46.26		1
21	Midpoint	Hunt	230.00	230.00	S Tower	0.70		2
22	Brady	Antelope	230.00	230.00	H Wood	56.41		1
23	Brady	Treasureton	230.00	230.00	H Wood	0.11		1
24	Brady #1 & #2	Kinport	230.00	230.00	S Tower	17.94		2
25	Brownlee	Ontario	230.00	230.00	S Tower	74.80		1
26	Mora	Bowmont	138.00	230.00	S P Wood	10.02		1
27	Mora	Bowmont	138.00	230.00	H Wood	8.75		1
28	Caldwell 710	Locust	230.00	230.00	SP Steel	18.60		1
29	Boise Bench	Caldwell	230.00	230.00	S Tower	7.73		1
30	Boise Bench	Caldwell	230.00	230.00	H Wood	33.49		1
31	Boise Bench	Cloverdale	230.00	230.00	S Tower	15.78		2
32	Boardman	Dalreed Sub	230.00	230.00	H Wood	1.67		1
33	Brownlee 714	Oxbow	230.00	230.00	SP Steel	11.04		2
34	Caldwell	Ontario	230.00	230.00	H Wood	30.10		1
35	Caldwell	Ontario	230.00	230.00	S Tower	3.14		1
36					TOTAL	4,861.24	11.02	203

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 ACSR	256,381	15,978,030	16,234,411					1
2X1780 ACSR		446,708	446,708					2
1272 ACSR		1,827,665	1,827,665					3
1272 ACSR								4
3X1272 ACSR		17,991,882	17,991,882					5
3X1272 ACSR		16,314,416	16,314,416					6
								7
1272 ACSR	483,309	5,295,240	5,778,549					8
795 ACSR	571,979	11,108,161	11,680,140					9
1272 ACSR	344,220	4,396,928	4,741,148					10
1272 ACSR		9,526,473	9,526,473					11
1272 ACSR								12
1272 ACSR		9,253,816	9,253,816					13
1272 ACSR								14
2X1272 ACSR		583,947	583,947					15
715.5 ACSR	283,143	8,600,241	8,883,384					16
715.5 ACSR	64,851	13,423,358	13,488,209					17
715.5 ACSR	51,448	224,249	275,697					18
								19
795 ACSR	62,218	7,067,375	7,129,593					20
715.5 ACSR	9,145	998,452	1,007,597					21
1272 ACSR	108,301	3,399,123	3,507,424					22
795 ACSR		6,186	6,186					23
715.5 ACSR	18,829	1,091,655	1,110,484					24
2X954 ACSR	1,676,838	20,541,790	22,218,628					25
715.5 ACSR	413,793	2,209,979	2,623,772					26
715.5 ACSR								27
1590 ACSR	2,376,936	8,775,086	11,152,022					28
1272 ACSR	1,748,214	7,619,965	9,368,179					29
715.5 ACSR								30
1272 ACSR	3,062,812	6,576,675	9,639,487					31
795 AAC		89,089	89,089					32
954 ACSR	34,174	16,026,470	16,060,644					33
2X954 ACSR	236,152	9,386,097	9,622,249					34
1272 ACSR								35
	33,098,328	592,880,317	625,978,645	6,975,999	1,302,613	4,139,757	12,418,369	36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/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.
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. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Bennett Mtn PP	Rattlesnake TS	230.00	230.00	SP Steel	4.43		1
2	Borah	Hunt	230.00	230.00	H Steel	68.18		1
3	Danskin	Hubbard	230.00	230.00	H Steel	36.29		1
4	Danskin	Hubbard	230.00	230.00	SP Steel	1.84		1
5	Danskin	Hubbard	230.00	230.00	SP Steel	1.30		2
6	Danskin	Bennett Mtn	230.00	230.00	SP Steel	5.39		1
7	Hemingway	Bowmont	230.00	230.00	SP Steel	13.02		1
8	Langley Gulch	Galloway Rd	138.00	230.00	SP Steel	14.19		1
9	Galloway Rd	Willis Tap	138.00	230.00	SP Steel	2.09		1
10	Walla Walla	Hurricane	230.00	230.00	H Wood	31.66		1
11	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.87		1
12	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.68		1
13	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.51		1
14	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.30		1
15	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.76		2
16	Oxbow	Brownlee	230.00	230.00	S Tower	10.40		2
17	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.49		1
18	Boise Bench	Midpoint #2	230.00	230.00	H Wood	102.17		1
19	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.11		2
20	Pallette Jct	Imnaha	230.00	230.00	H Wood	24.43		2
21	Hells Canyon	Palette Jct	230.00	230.00	S Tower	9.05		2
22	Brownlee	Boise Bench	230.00	230.00	S Tower	102.55		2
23	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.29		1
24	Palette Jct	Enterprise	230.00	230.00	H Wood	29.60		1
25	Borah	Brady #2	230.00	230.00	S Tower	0.46		1
26	Borah	Brady #2	230.00	230.00	H Wood	3.52		1
27	Borah	Brady #1	230.00	230.00	H Wood	3.87		1
28								
29	Goshen	State Line	161.00	161.00	H Wood	40.93		1
30	Don	Goshen	161.00	161.00	S Tower	2.37		2
31	Don	Goshen	161.00	161.00	H Wood	48.42		2
32	Antelope	Goshen	161.00	161.00	H Wood	5.67		1
33	Goshen	State Line	161.00	161.00	H Wood	10.94		1
34	Goshen	State Line	161.00	161.00	H Wood	7.87		1
35								
36					TOTAL	4,861.24	11.02	203

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
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9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272 ACSR	81,701	1,666,354	1,748,055					1
1590 ACSR	624,917	22,467,321	23,092,238					2
1590 ACSR		15,210,561	15,210,561					3
1590 ACSR								4
1590 ACSR								5
1590 ACSR		3,528,033	3,528,033					6
1590 ACSR	1,854,996	9,277,980	11,132,976					7
1590 ACSR	948,166	9,080,890	10,029,056					8
1272 ACSR								9
1272 ACSR		6,255,536	6,255,536					10
715.5 ACSR	385,287	11,685,424	12,070,711					11
715.5 ACSR								12
795 ACSR	53,068	4,881,772	4,934,840					13
795 ACSR								14
VARIOUS	289,934	8,966,987	9,256,921					15
1272 ACSR	14,810	1,237,524	1,252,334					16
715.5 ACSR	227,825	17,008,591	17,236,416					17
VARIOUS								18
1272 ACSR	87,468	3,902,140	3,989,608					19
1272 ACSR	171,081	1,673,662	1,844,743					20
1272 ACSR	44,687	1,252,130	1,296,817					21
954 ACSR	184,817	6,257,154	6,441,971					22
715.5 ACSR	247,857	8,064,231	8,312,088					23
1272 ACSR	84,014	1,903,192	1,987,206					24
1272 ACSR	3,068	531,106	534,174					25
715.5 ACSR								26
1272 ACSR	7,248	421,273	428,521					27
								28
250 COPPER	565,311	3,524,164	4,089,475					29
715.5 ACSR	88,204	2,654,354	2,742,558					30
397.5 ACSR								31
397.5 ACSR		784,659	784,659					32
250 COPPER		203,534	203,534					33
250 COPPER		135,690	135,690					34
								35
	33,098,328	592,880,317	625,978,645	6,975,999	1,302,613	4,139,757	12,418,369	36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	15.72		2
2	American Falls Power Plant	Adelaide	138.00	138.00	S P Wood	0.12		2
3	Minidoka Loop	Adelaide	138.00	138.00	S Tower	1.14		2
4	Nampa	Caldwell	138.00	138.00	S P Wood	10.06		2
5	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	54.46		1
6	Upper Salmon	Cliff	138.00	138.00	H Wood	30.81		1
7	Eastgate	Russet	138.00	138.00	S P Wood	2.06		1
8	Brady	Fremont	138.00	138.00	S Tower	1.04		2
9	Brady	Fremont	138.00	138.00	H Wood	24.38		2
10	Brady	Fremont	138.00	138.00	S P Wood	24.33		2
11	King	Lower Malad	138.00	138.00	H Wood	84.74		2
12	Emmett Jct	Payette	138.00	138.00	H Wood	66.49		2
13	Mountain Home AFB Tap		138.00	138.00	H Wood	6.20		1
14	Ontario	Quartz	138.00	138.00	H Wood	73.40		1
15	King	American Falls PP	138.00	138.00	S Tower	0.93		2
16	King	American Falls PP	138.00	138.00	H Wood	142.41		1
17	King	American Falls PP	138.00	138.00	S P Wood	3.71		1
18	Duffin	Clawson	138.00	138.00	H Wood	6.23		1
19	American Falls	Brady Tie	138.00	138.00	H Wood	0.33		1
20	Upper Salmon A-B	King	138.00	138.00	H Wood	5.66		1
21	Upper Salmon B	Wells	138.00	138.00	H Wood	125.56		1
22	King	Wood River	138.00	138.00	H Wood	64.13		1
23	Toponis	Pocket	138.00	138.00	S P Wood	9.80		1
24	Boise Bench	Grove	138.00	138.00	S P Wood	10.39		2
25	Quartz	John Day	138.00	138.00	H Wood	67.32		1
26	Sinker Creek Tap		138.00	138.00	H Wood	2.80		1
27	Mora	Cloverdale	138.00	138.00	H Wood	2.53		1
28	Mora	Cloverdale	138.00	138.00	S P Wood	22.28		1
29	Mora	Cloverdale	138.00	138.00	S P Steel	0.96		2
30	Stoddard Jct	Stoddard Sub	138.00	138.00	S P Steel	3.80		1
31	Fossil Gulch Tap		138.00	138.00	H Wood	1.95		1
32	Wood River	Midpoint	138.00	138.00	H Wood	53.08		2
33	Wood River	Midpoint	138.00	138.00	S P Wood	16.69		2
34	Oxbow	McCall	138.00	138.00	H Wood	37.15		1
35	Oxbow	McCall	138.00	138.00	S P Wood	2.32		1
36					TOTAL	4,861.24	11.02	203

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
250 COPPER	26,507	381,162	407,669					1
250 COPPER								2
715.5 ACSR	21,327	249,232	270,559					3
795 AAC	719,463	3,312,460	4,031,923					4
795 ACSR	78,078	4,097,356	4,175,434					5
795 ACSR	43,568	2,779,262	2,822,830					6
795 AAC	270,823	561,561	832,384					7
VARIOUS	564,932	4,128,640	4,693,572					8
VARIOUS								9
VARIOUS								10
VARIOUS	76,823	3,169,100	3,245,923					11
VARIOUS	55,521	2,908,212	2,963,733					12
397.5 ACSR	5,274	6,930	12,204					13
VARIOUS	34,428	6,772,340	6,806,768					14
715.5 ACSR	216,919	10,516,799	10,733,718					15
715.5 ACSR								16
715.5 ACSR								17
4\0	4,191	469,369	473,560					18
954 ACSR		96,921	96,921					19
250 COPPER	2,741	753,925	756,666					20
VARIOUS	28,490	3,501,408	3,529,898					21
VARIOUS	173,683	17,045,847	17,219,530					22
397.5 ACSR								23
VARIOUS	225,602	1,648,079	1,873,681					24
397.5 ACSR	96,582	2,556,237	2,652,819					25
VARIOUS	11,252	133,322	144,574					26
715.5 ACSR	3,101,778	8,719,127	11,820,905					27
VARIOUS								28
795AAC								29
1272 ACSR								30
250 COPPER	450	187,848	188,298					31
397.5 ACSR	349,712	7,127,142	7,476,854					32
397.5 ACSR								33
397.5 ACSR	141,534	2,753,958	2,895,492					34
397.5 ACSR								35
	33,098,328	592,880,317	625,978,645	6,975,999	1,302,613	4,139,757	12,418,369	36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/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.
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. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Lowell Jct	Nampa	138.00	138.00	S P Wood	7.50		2
2	Hunt	Milner	138.00	138.00	S P Wood	19.40		1
3	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.49		1
4	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.46		2
5	Pingree	Haven	138.00	138.00	S P Wood	11.72		1
6	Midpoint	Twin Falls	138.00	138.00	S P Wood	25.22		2
7	Twin Falls	Russett	138.00	138.00	S P Wood	1.71		1
8	Blackfoot	Aiken	46.00	138.00	S P Wood	6.22		2
9	Peterson	Tendoy	69.00	138.00	H Wood	57.10		1
10	Eastgate Tap	Eastgate	138.00	138.00	S P Wood	6.36		1
11	Kimberly Tap	Kimberly	138.00	138.00	S P Steel	1.84		2
12	Boise Bench	Mora	138.00	138.00	H Wood	13.14		2
13	Bowmont-Caldwell	Simplot Sub	138.00	138.00	S P Wood	0.51		1
14	Gary Lane	Eagle	138.00	138.00	S P Wood	6.66		1
15	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	9.25	2.98	1
16	Boise Bench	Butler	138.00	138.00	S P Wood	0.14	4.02	1
17	Eagle	Star	138.00	138.00	S P Wood	6.74		1
18	Karcher Sub	Zilog Tap	138.00	138.00	S P Steel	3.60		1
19	Cloverdale - 712	712 - Wye	138.00	138.00	S P Steel	0.42	4.02	1
20	Victory Jct	Victory	138.00	138.00	S P Steel	1.89		1
21	Butler	Wye	138.00	138.00	S P Steel	2.94		1
22	Horseflat	Starkey	138.00	138.00	H Wood	33.97		1
23	Starkey	Mccall	138.00	138.00	S P Steel	2.23		2
24	Starkey	Mccall	138.00	138.00	H Wood	3.80		1
25	Starkey	Mccall	138.00	138.00	S P Steel	1.50		1
26	Starkey	Mccall	138.00	138.00	S P Wood	17.61		1
27	Chestnut	Happy Valley	138.00	138.00	S P Steel	2.78		1
28	Garnet	Ward		138.00				
29	McCall	Lake Fork	138.00	138.00	S P Wood	8.89		1
30	McCall	Lake Fork	138.00	138.00	S Steel	2.90		
31	Caldwell	Willis	138.00	138.00	S P Steel	1.30		1
32	Caldwell	Willis	138.00	138.00	S P Steel	1.59		1
33	Caldwell	Willis	138.00	138.00	S P Wood	0.87		1
34	Valivue Tap		138.00	138.00	S P Steel	0.80		2
35	Bowmont	Happy Valley	138.00	138.00	S P Steel	8.72		1
36					TOTAL	4,861.24	11.02	203

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
715.5 ACSR	211,131	1,454,879	1,666,010					1
715.5 ACSR	3,324	1,426,231	1,429,555					2
397.5 ACSR	14,927	616,667	631,594					3
715.5 ACSR	13,734	1,073,502	1,087,236					4
397.5 ACSR	18,223	1,281,344	1,299,567					5
VARIOUS	66,286	3,293,716	3,360,002					6
715.5 ACSR	16,790	213,033	229,823					7
715.5 ACSR	13,616	529,756	543,372					8
397.5 ACSR	395,696	3,504,326	3,900,022					9
715.5 ACSR	343,955	2,221,809	2,565,764					10
795 ACSR								11
715.5 ACSR	14,697	862,367	877,064					12
795 AAC		50,319	50,319					13
795 AAC	489,037	2,454,557	2,943,594					14
1272 ACSR	935,810	3,551,499	4,487,309					15
1272 ACSR	34,687	838,605	873,292					16
715.5 ACSR	179,817	2,932,783	3,112,600					17
795 AAC	43,035	434,341	477,376					18
1272 ACSR	140,412	2,577,075	2,717,487					19
1272 ACSR								20
795 ACSR	134,471	1,405,436	1,539,907					21
715.5 ACSR	2,473,833	18,781,405	21,255,238					22
715.5 ACSR								23
715.5 ACSR								24
715.5 ACSR								25
715.5 ACSR								26
1272 ACSR	78,579	2,219,508	2,298,087					27
	40,580		40,580					28
715.5 ACSR	331,539	4,682,879	5,014,418					29
								30
1272 ACSR	272,231	2,141,218	2,413,449					31
795 ACSR								32
795 ACSR								33
795 ACSR		351,497	351,497					34
1272 ACSR	691,728	6,045,286	6,737,014					35
	33,098,328	592,880,317	625,978,645	6,975,999	1,302,613	4,139,757	12,418,369	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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.
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. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Antelope	Scoville	138.00	138.00	H Wood	0.12		1
2	American Falls	Wheelon	138.00	138.00	H Wood	1.05		1
3	Kinport	Don #1	138.00	138.00	S Tower	1.32		2
4	Donn	HOKU	138.00	138.00	S P Steel	2.72		1
5	HOKU	Alamed	138.00	138.00	S P Steel	0.22		2
6	HOKU	Alamed	138.00	138.00	S P Steel	0.23		2
7	HOKU	Alamed	138.00	138.00	S P Steel	2.85		1
8	Rockland Jct	Rockland Wind Farm	138.00	138.00	S P Steel	5.30		1
9	King	Justice	138.00	138.00	S P Wood	0.11		1
10	NorthView Tap		138.00	138.00	S P Wood	6.17		1
11	Twin Falls PP Tap		138.00	138.00	H Wood	0.99		1
12	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.38		1
13	Lower Salmon	King Tie	138.00	138.00	H Wood	0.11		1
14	C J Strike	Strike Jct	138.00	138.00	S Tower	4.30		2
15	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	23.42		1
16	Strike Jct	Bowmont		138.00	H Wood	0.05		1
17	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
18	Strike Jct	Bowmont	138.00	138.00	H Wood	68.16		1
19	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.48		2
20	Bliss	King	138.00	138.00	H Wood	10.47		1
21	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.30		1
22	Swan Falls Tap		138.00	138.00	H Wood	1.00		1
23								
24								
25								
26	Hines	BPA (Harney)	115.00	115.00	H Wood	3.35		1
27								
28								
29	69 Kv Lines		69.00	69.00	H Wood	210.65		1
30	69 Kv Lines		69.00	69.00	S P Wood	928.75		1
31								
32								
33	46 Kv Lines		46.00	46.00	S P Wood	431.16		1
34								
35	Total all lines					4,861.24	11.02	203
36					TOTAL	4,861.24	11.02	203

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
397.5 ACSR		71,018	71,018					1
250 COPPER		96,431	96,431					2
715.5 ACSR	1,174	206,258	207,432					3
1272 ACSR	190	4,594	4,784					4
1272 ACSR								5
795 ACSR								6
795 ACSR								7
795 ACSR		-16,973	-16,973					8
1590 ACSR		60,659	60,659					9
715.5 ACSR	105,933	4,125,054	4,230,987					10
250 COPPER	58	63,264	63,322					11
715.5 ACSR		179,047	179,047					12
397.5 ACSR		4,406	4,406					13
715.5 ACSR	1,074	622,115	623,189					14
397.5 ACSR	6,332	2,562,490	2,568,822					15
715.5 ACSR	86,651	2,861,709	2,948,360					16
715.5 ACSR								17
								18
715.5 ACSR	7	279,481	279,488					19
715.5 ACSR	5,620	1,352,664	1,358,284					20
715.5 ACSR	2,814	183,606	186,420					21
397.5 ACSR	17,207	261,512	278,719					22
								23
								24
								25
397.5 ACSR	1,978	63,404	65,382					26
								27
								28
VARIOUS	1,699,736	70,925,208	72,624,944					29
VARIOUS								30
								31
								32
VARIOUS	194,536	18,820,777	19,015,313					33
				6,975,999	1,302,613	4,139,757	12,418,369	34
	33,098,328	592,880,317	625,978,645	6,975,999	1,302,613	4,139,757	12,418,369	35
	33,098,328	592,880,317	625,978,645	6,975,999	1,302,613	4,139,757	12,418,369	36

Schedule Page: 422 Line No.: 1 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 73.2% of this 85.4 mile line.

Schedule Page: 422 Line No.: 2 Column: b
This line is jointly owned with Portland General Electric and Idaho Power owns 10.0% of this 17.8 mile line.

Schedule Page: 422 Line No.: 3 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 22.0% of this 241.3 mile line.

Schedule Page: 422 Line No.: 4 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 37.0% of this 129.3 mile line.

Schedule Page: 422 Line No.: 5 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 22.0% of this 241.3 mile line.

Schedule Page: 422 Line No.: 6 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 37.0% of this 129.3 mile line.

Schedule Page: 422 Line No.: 8 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this 226.6 mile line.

Schedule Page: 422 Line No.: 10 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 73.2% of this 27.1 mile line.

Schedule Page: 422 Line No.: 11 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this approximately 193 mile line.

Schedule Page: 422 Line No.: 12 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this 41.2 mile line.

Schedule Page: 422 Line No.: 13 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this approximately 193 mile line.

Schedule Page: 422 Line No.: 14 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this 47.3 mile line.

Schedule Page: 422 Line No.: 15 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 18.3% of this 40.9 mile line.

Schedule Page: 422 Line No.: 16 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 64.4% of this 79.5 mile line.

Schedule Page: 422 Line No.: 17 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 64.4% of this 77.9 mile line.

Schedule Page: 422 Line No.: 18 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 64.4% of this 0.9 mile line.

Schedule Page: 422 Line No.: 32 Column: b
This line is jointly owned with Portland General Electric and Idaho Power owns 10.0% of this 16.7 mile line.

Schedule Page: 422.1 Line No.: 10 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 40.8% of this 77.6 mile line.

Schedule Page: 422.1 Line No.: 29 Column: b

This line is jointly owned with PacifiCorp. Idaho Power owns 37.8% of Goshen- Jefferson 28.9 mile segment, 37.8% of the Jefferson- Big Grassy 20.8 mile segment and 100% of the Big Grassy- State Line 40.9 mile segment.

Schedule Page: 422.1 Line No.: 32 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 21.9% of this 25.8 mile line.

Schedule Page: 422.1 Line No.: 33 Column: b

This line is jointly owned with PacifiCorp. Idaho Power owns 37.8% of Goshen- Jefferson 28.9 mile segment, 37.8% of the Jefferson- Big Grassy 20.8 mile segment and 100% of the Big Grassy- State Line 40.9 mile segment.

Schedule Page: 422.1 Line No.: 34 Column: b

This line is jointly owned with PacifiCorp. Idaho Power owns 37.8% of Goshen- Jefferson 28.9 mile segment, 37.8% of the Jefferson- Big Grassy 20.8 mile segment and 100% of the Big Grassy- State Line 40.9 mile segment.

Schedule Page: 422.4 Line No.: 1 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 11.5% of this 1 mile line.

Schedule Page: 422.4 Line No.: 2 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 7.2% of this 29.1 mile line.

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	No new lines for 2016						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
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21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
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									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
									44

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Adelaide	transmission	345.00	138.00	13.80
2	Aiken	distribution	46.00	13.00	
3	Alameda	distribution	138.00	13.00	
4	Alameda	distribution	138.00	13.09	
5	American Falls PP - attended	transmission	138.00	13.80	
6	American Falls	transmission	138.00	46.00	12.47
7	Antelope	transmission	230.00	161.00	13.80
8	Artesian	distribution	46.00	13.00	
9	Bannock Creek	distribution	46.00	13.00	
10	Bennett Mountain Power Plant- attended	transmission	230.00	18.00	
11	Bennett Mountain Power Plant- attended	distribution	18.00	4.16	
12	Bethel Court	distribution	138.00	13.00	
13	Big Grassy	transmission	161.00		
14	Black Cat	distribution	138.00	13.09	
15	Blackfoot	distribution	46.00	13.00	
16	Blackfoot	transmission	161.00	46.00	12.47
17	Blackfoot	distribution	161.00	138.00	12.98
18	Bliss - attended	transmission	138.00	13.80	
19	Blue Gulch	distribution	138.00	35.00	
20	Boise Bench - attended	transmission	230.00	138.00	13.20
21	Boise Bench - attended	distribution	138.00	35.00	
22	Boise Bench - attended	transmission	138.00	69.00	12.98
23	Boise Bench - attended	transmission	230.00	138.00	13.80
24	Boise	distribution	138.00	13.00	
25	Borah	transmission	345.00	230.00	13.80
26	Bowmont	distribution	69.00	46.00	6.90
27	Bowmont	distribution	138.00	35.00	
28	Bowmont	transmission	138.00	69.00	12.98
29	Bowmont	transmission	138.00	69.00	12.47
30	Bowmont	transmission	230.00	138.00	13.80
31	Brady	transmission	230.00	138.00	13.80
32	Brady	transmission	138.00	46.00	12.47
33	Brady	distribution	46.00	13.00	
34	Brownlee - attended	transmission	230.00	13.80	
35	Bruneau Bridge	distribution	138.00	35.00	
36	Bruneau Bridge	distribution	138.00	36.20	
37	Buckhorn	distribution	69.00	35.00	
38	Bucyrus	distribution	46.00	7.20	
39	Buhl	distribution	46.00	13.20	
40	Burley Rural	distribution	69.00	13.00	

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
300	2					1
20	2					2
18	1					3
18	1					4
72	1					5
25	1					6
224	1					7
10	1					8
10	1					9
135	1					10
5	1					11
15	1					12
						13
48	2					14
30	2					15
50	3	1				16
80	1					17
69	3					18
15	1					19
254	2					20
42	2					21
75	3					22
240	2					23
67	3					24
450	3	1				25
8	3					26
18	1					27
25	1					28
25	1					29
360	2					30
312	3					31
		1				32
15	1	6				33
721	5	1				34
18	1					35
24	1					36
20	1					37
6	1	1				38
		1				39
12	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Butler	distribution	138.00	13.09	
2	Caldwell	distribution	138.00	13.00	
3	Caldwell	transmission	230.00	138.00	
4	Caldwell	distribution	138.00	13.09	
5	Caldwell	transmission	138.00	69.00	12.47
6	Caldwell	transmission	230.00	138.00	12.47
7	Caldwell	distribution	13.00	4.16	
8	Canyon Creek	distribution	138.00	35.00	
9	Canyon Creek	transmission	138.00	69.00	12.98
10	Cascade Power Plant - attended	transmission	69.00	4.60	
11	Cascade	distribution	69.00	13.00	
12	Cascade	distribution	69.00	13.10	
13	Cascade	distribution	25.00		
14	Chestnut	distribution	138.00	13.00	
15	Chestnut	distribution	138.00	13.09	
16	Clear Lake - attended	transmission	46.00	2.40	
17	Cliff	transmission	138.00	46.00	12.50
18	Cliff	transmission	138.00	46.00	12.95
19	Cloverdale	distribution	138.00	13.00	
20	Cloverdale	distribution	138.00	13.09	
21	Dale	distribution	46.00	4.60	
22	Dale	distribution	46.00	13.00	
23	Dale	distribution	69.00	13.00	
24	Dale	distribution	138.00	36.20	
25	Dale	transmission	138.00	46.00	12.47
26	Danskin- attended	transmission	230.00	18.00	
27	Danskin- attended	transmission	230.00	138.00	13.80
28	Danskin- attended	distribution	18.00	4.16	
29	Danskin- attended	transmission	138.00	12.00	
30	Danskin- attended	distribution	35.00	13.80	
31	Don	distribution	138.00	7.60	
32	Don	distribution	138.00	13.20	
33	Don	distribution	138.00	13.00	
34	Don	distribution	14.00		
35	DRAM	distribution	138.00	13.09	
36	DRAM	transmission	230.00	138.00	13.80
37	DRAM	distribution	138.00	12.47	
38	DRAM	distribution	138.00	13.00	
39	Duffin	distribution	138.00	35.00	
40	Eagle	distribution	138.00	13.09	

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
48	2					1
15	1					2
120	1					3
24	1					4
75	3					5
120	1					6
		1				7
15	1					8
15	1					9
12	1					10
5	1					11
10	1					12
4	1					13
24	1					14
24	1					15
4	1					16
12	2	1				17
4	1					18
24	1					19
24	1					20
		1				21
8	1	6				22
		1				23
27	1					24
25	1					25
140	1					26
180	1					27
6	1					28
96	2					29
5	1					30
		1				31
108	6	1				32
26	1					33
80	6					34
101	6					35
160	2					36
17	1					37
17	1					38
36	2					39
38	2					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Eastgate	distribution	138.00		
2	Eastgate	distribution	138.00	13.00	
3	Eckert	distribution	138.00	36.20	
4	Eden	distribution	138.00	36.20	
5	Eden	transmission	138.00	46.00	12.98
6	Elkhorn	distribution	138.00	12.47	
7	Elkhorn	distribution	138.00	13.00	
8	Elmore	distribution	138.00	35.00	
9	Elmore	transmission	138.00	69.00	12.50
10	Elmore	transmission	138.00	69.00	12.98
11	Emmett	distribution	138.00		
12	Emmett	transmission	138.00	69.00	12.47
13	Falls	distribution	46.00	13.00	
14	Falls	distribution	46.00		
15	Filer	distribution	46.00	13.00	
16	Flat Top	distribution	46.00	13.00	
17	Flying H	distribution	69.00	2.40	
18	Fort Hall	distribution	46.00	13.00	
19	Fossil Gulch	distribution	138.00	35.00	
20	Fremont	transmission	138.00	46.00	12.50
21	Gary	distribution	138.00	13.09	
22	Gary	distribution	138.00	13.00	
23	Gem	distribution	69.00	13.00	
24	Gem	distribution	69.00		
25	Gooding Rural	distribution	46.00	13.00	
26	Golden Valley	distribution	69.00	13.00	
27	Goshen	transmission	345.00	161.00	69.00
28	Gowen Substation	distribution	138.00	35.00	
29	Grindstone	distribution	35.00		
30	Grove	distribution	138.00	13.09	
31	Grove	distribution	138.00	13.00	
32	Hagerman	distribution	46.00	13.00	
33	Hagerman	distribution	69.00	13.00	
34	Hailey	distribution	138.00	13.00	
35	Happy Valley	distribution	138.00	13.09	
36	Haven	distribution	138.00	35.00	
37	Haven	transmission	138.00	46.00	
38	Hemingway	transmission	500.00	230.00	34.50
39	Hewlett Packard	distribution	138.00	13.00	
40	Hidden Springs	distribution	138.00	13.00	

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
24	1					1
18	1					2
18	1					3
24	1					4
15	1					5
8	1					6
8	1					7
17	1					8
15	1					9
15	1					10
24	1					11
25	1					12
8	1					13
10	1					14
10	1					15
13	2					16
15	2					17
10	1	1				18
15	1					19
50	3	1				20
20	1					21
17	1					22
8	1					23
10	1					24
15	2					25
10	1	1				26
908	4					27
24	1					28
10	2					29
48	2					30
24	1					31
10	1					32
5	1					33
20	1					34
18	1					35
12	1					36
25	1					37
600	3	1				38
20	1					39
8	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2017	End of 2016/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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Highland	distribution	138.00	13.00	
2	Hill	distribution	138.00	13.00	
3	Hillsdale	distribution	138.00		
4	Hoku	distribution	138.00	13.80	
5	Homedale	distribution	69.00	13.00	
6	Horse Flat	transmission	230.00	138.00	13.80
7	Horseshoe Bend	distribution	35.00		
8	Horseshoe Bend	distribution	69.00	36.20	
9	Horseshoe Bend	distribution	69.00	25.00	
10	Huston	distribution	69.00	13.00	
11	Hulen	distribution	46.00	13.00	
12	Hunt	transmission	230.00	138.00	13.80
13	Hydra	distribution	138.00	36.20	
14	Island	distribution	69.00	13.00	
15	Jefferson	transmission	161.00		
16	Jerome	distribution	138.00	13.00	
17	Jerome	distribution	138.00	13.09	
18	Julion Clawson	distribution	138.00	35.00	
19	Joplin	distribution	138.00	13.00	
20	Joplin	distribution	138.00	35.00	
21	Justice	transmission	230.00	138.00	13.80
22	Karcher	distribution	138.00	13.00	
23	Kenyon	distribution	69.00	13.00	
24	Ketchum	distribution	138.00	13.00	
25	Kimberly	distribution	138.00	13.09	
26	Kinport	transmission	161.00	46.00	13.20
27	Kinport	transmission	230.00	138.00	12.47
28	Kinport	transmission	230.00	138.00	13.80
29	Kinport	transmission	345.00	230.00	13.80
30	Kramer	distribution	138.00	35.00	
31	Kramer	distribution	138.00	36.20	
32	Kuna	distribution	138.00	13.00	
33	Lake	distribution	69.00	13.00	
34	Lake Fork	distribution	138.00	36.20	
35	Lake Fork	transmission	138.00	69.00	12.50
36	Lamb	distribution	138.00	13.00	
37	Langley Gulch- attended	transmission	230.00	138.00	13.80
38	Langley Gulch- attended	transmission	230.00		
39	Langley Gulch- attended	distribution		4.16	
40	Langley Gulch- attended	distribution	13.00	4.16	

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
18	1					1
39	2					2
24	1					3
		2				4
22	2					5
100	1					6
5	1					7
12	1					8
5	1					9
10	1					10
10	1					11
300	3					12
48	2					13
12	1					14
						15
20	1					16
20	1					17
30	2					18
15	1					19
18	1					20
180	1					21
12	1					22
20	2					23
42	2					24
27	1	1				25
		7				26
180	1					27
180	1					28
600	3	1				29
12	1					30
18	1					31
15	1					32
10	1					33
18	1					34
15	1					35
18	1					36
360	2					37
246	2					38
12	1					39
12	1					40

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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Langley Gulch- attended	transmission	230.00	150.00	
2	Lansing	distribution	69.00	13.00	
3	Lincoln	distribution	138.00	13.09	
4	Linden	distribution	138.00	13.00	
5	Locust	distribution	138.00	36.20	
6	Locust	transmission	230.00	138.00	13.80
7	Lower Malad - attended	transmission	138.00	7.20	
8	Lower Salmon - attended	transmission	138.00	13.80	
9	Map Rock	distribution	69.00	13.00	
10	McCall	distribution	13.00	13.09	
11	McCall	distribution	138.00	36.20	
12	Meridian	distribution	138.00	13.00	
13	Micron	distribution	138.00	13.09	
14	Micron	distribution	138.00	13.00	
15	Midpoint	transmission	230.00	138.00	13.80
16	Midpoint	transmission	345.00	230.00	13.80
17	Midpoint	transmission	500.00	345.00	
18	Midrose	distribution	138.00	13.09	
19	Milner	transmission	138.00	69.00	12.47
20	Milner	distribution	69.00	46.00	6.90
21	Milner	distribution	138.00	35.00	
22	Milner PP - attended	transmission	138.00	13.80	
23	Moonstone	distribution	138.00	35.00	
24	Mora	distribution	138.00	13.09	
25	Mora	distribution	138.00	36.20	
26	Moreland	distribution	35.00	13.00	
27	Moreland	distribution	46.00	13.00	
28	Moreland	distribution	46.00	35.00	12.47
29	Mountain Home	distribution	69.00	13.00	
30	Mountain Home Air Force Base	distribution	69.00	13.00	
31	Mountain Home Air Force Base	distribution	138.00	13.00	
32	Nampa	transmission	230.00	138.00	13.80
33	Nampa	distribution	138.00	13.00	
34	New Meadows	distribution	138.00	36.20	
35	New Plymouth	distribution	69.00	13.00	
36	Northview	distribution	138.00		
37	Notch Butte	distribution	138.00	13.09	
38	Orchard	distribution	69.00	36.20	
39	Orchard	distribution	69.00	35.00	12.47
40	Orchard	distribution	69.00		

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
		1				1
12	1					2
10	1					3
33	2					4
72	3					5
360	2					6
16	1					7
70	4					8
10	1					9
12	1					10
18	1					11
36	2					12
24	2					13
24	2					14
120	1					15
840	2	1				16
860	3	1				17
24	1					18
75	3	1				19
8	3	1				20
29	2					21
36	1					22
12	1					23
24	1					24
24	1					25
6	1					26
8	1					27
6	3	1				28
15	1					29
		1				30
18	1					31
180	1					32
50	3					33
12	1					34
10	1					35
24	1					36
10	1					37
6	1					38
10	3					39
		1				40

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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Parma	distribution	69.00	13.00	
2	Parma	distribution	69.00	35.00	
3	Paul	distribution	138.00	35.00	
4	Paul	distribution	138.00	36.20	
5	Payette	distribution	138.00	13.00	
6	Pingree	transmission	138.00	46.00	12.50
7	Pingree	distribution	138.00	35.00	
8	Pleasant Valley	distribution	138.00	35.00	
9	Pleasant Valley	distribution	138.00	36.20	
10	Pocatello	distribution	46.00	13.00	
11	Pocket	distribution	138.00	36.20	
12	Poleline	distribution	138.00	13.09	
13	Populus	transmission	345.00		
14	Portneuf	distribution	138.00	35.00	
15	Portneuf	distribution	46.00	35.00	
16	Rockford	distribution	46.00	13.00	
17	Russett	distribution	138.00	13.00	
18	Sailor Creek	distribution	138.00	2.40	
19	Sailor Creek	distribution	138.00	35.00	
20	Salmon	distribution	69.00	13.00	
21	Salmon	distribution	69.00	34.50	12.47
22	Salmon	distribution	69.00		12.47
23	Salmon	transmission	13.00	2.40	
24	Salmon	distribution	69.00	7.20	
25	Shoshone	distribution	46.00	13.00	
26	Shoshone	distribution	46.00	7.20	
27	Shoshone Falls - attended	transmission	46.00	2.30	
28	Shoshone Falls - attended	transmission	46.00	6.60	
29	Silver	distribution	138.00	35.00	
30	Simplot	distribution	138.00	13.00	
31	Sinker Creek	distribution	138.00	35.00	
32	Siphon	distribution	138.00	35.00	
33	South Park	distribution	46.00	13.00	
34	Star	distribution	138.00	13.09	
35	Starkey	transmission	138.00	69.00	12.47
36	State	distribution	69.00	13.00	
37	Stoddard	distribution	138.00	13.00	
38	Strike Power Plant - attended	transmission	138.00	13.80	
39	Sugar	distribution	138.00	35.00	
40	Swan Falls - attended	transmission	138.00	6.90	

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
10	1					1
12	1					2
18	1	1				3
27	1					4
23	3					5
50	3					6
22	2					7
18	1					8
24	1					9
36	2					10
24	1					11
18	1					12
						13
18	1					14
		1				15
14	2					16
18	1					17
15	2					18
15	1					19
10	1	3				20
10	3					21
		2				22
5	2					23
		1				24
10	1					25
2	3					26
3	1					27
10	1					28
12	1					29
30	2					30
12	1					31
33	2					32
10	1					33
18	1					34
18	1					35
33	2					36
15	1					37
83	3					38
20	2					39
18	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Taber	distribution	46.00	13.00	
2	Ten Mile	distribution	138.00	13.09	
3	Terry	distribution	138.00	13.09	
4	Terry	distribution	138.00	13.00	
5	Thousand Springs - attended	transmission	46.00	7.20	
6	Thousand Springs - attended	transmission	7.00	2.40	
7	Three Mile Knoll	transmission	345.00		
8	Toponis	distribution	138.00	33.00	
9	Twin Falls	distribution	138.00	13.09	
10	Twin Falls	transmission	138.00	46.00	12.98
11	Twin Falls PP - attended	transmission	138.00	7.20	
12	Twin Falls PP - attended	transmission	138.00	13.20	
13	Upper Malad - attended	transmission	45.00	7.20	
14	Upper Salmon- attended	transmission	138.00	7.20	
15	Ustick	distribution	138.00	13.00	
16	Vallivue	distribution	138.00	13.09	
17	Victory	distribution	138.00	13.00	
18	Victory	distribution	138.00	13.09	
19	Ware	distribution	69.00	13.00	
20	Weiser	distribution	69.00	13.00	
21	Weiser	transmission	138.00	69.00	12.47
22	Wilder	distribution	69.00	13.00	
23	Willis	distribution	138.00	13.09	
24	Wye	distribution	138.00	13.00	
25	Wye	distribution	138.00	13.09	
26	Zilog	distribution	138.00	13.09	
27					
28					
29	The above are all State of Idaho				
30					
31	Montana:				
32	Mill Creek	transmission	230.00		
33	Peterson	transmission	230.00	69.00	13.20
34					
35	Nevada:				
36	Valmy - attended	transmission	345.00	18.00	
37	Valmy - attended	transmission	345.00	22.00	
38	Wells	transmission	138.00	69.00	13.00
39					
40	Oregon:				

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
5	1					1
48	2					2
12	1					3
30	2					4
8	1					5
		1				6
						7
18	1					8
44	2					9
33	2					10
9	1					11
72	1					12
8	1					13
36	4					14
44	2					15
18	1					16
24	1					17
18	1					18
12	1	1				19
20	2					20
25	1					21
10	1					22
18	1					23
36	2					24
20	1					25
24	1					26
						27
						28
						29
						30
						31
						32
24	3	1				33
						34
						35
315	1					36
300	1					37
20	3	1				38
						39
						40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2017	Year/Period of Report End of 2016/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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Boardman - attended	transmission	500.00	24.00	
2	Boardman - attended	transmission	230.00	7.20	
3	Boardman - attended	transmission	24.00	7.20	
4	Burns	transmission	500.00		
5	Cairo	distribution	69.00	13.00	
6	Hells Canyon - attended	transmission	230.00	13.80	
7	Hells Canyon - attended	distribution	69.00	0.50	
8	Hines	transmission	138.00	115.00	12.47
9	Hurricane	transmission	230.00		
10	Malheur Butte	distribution	69.00	34.50	
11	Nyssa	distribution	69.00	13.00	
12	Ontario	distribution	138.00	13.00	
13	Ontario	transmission	138.00	69.00	12.47
14	Ontario	transmission	230.00	138.00	13.80
15	Ontario	transmission	138.00	69.00	12.98
16	Ontario	transmission	138.00	69.00	13.09
17	Ontario	transmission	138.00	69.00	12.50
18	Ore-Ida	distribution	69.00	13.00	
19	Oxbow - attended	transmission	138.00	69.00	13.00
20	Oxbow - attended	transmission	230.00	13.80	
21	Oxbow - attended	transmission	230.00	138.00	13.80
22	Quartz	transmission	138.00	69.00	12.50
23	Quartz	transmission	230.00	138.00	12.98
24	Quartz	transmission	138.00	69.00	12.98
25	Summer Lake	transmission	500.00		
26	Vale	distribution	69.00	13.00	
27					
28	Washington:				
29	Walla Walla	transmission	230.00		
30					
31	Wyoming:				
32	Jim Bridger - attended	transmission	345.00	22.00	34.50
33					
34					
35					
36					
37					
38	Transformers-distribution substations under 10,000				
39	KVA 82 unattended.				
40					

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
685	3					1
55	1					2
55	1					3
						4
12	1					5
500	3	1				6
1	1					7
40	1					8
						9
8	3	1				10
20	2					11
38	2					12
25	1	1				13
240	2					14
50	2					15
		1				16
		1				17
15	1					18
10	3	1				19
244	2					20
100	1					21
15	1					22
100	3	1				23
15	1					24
						25
10	1					26
						27
						28
						29
						30
						31
2244	4					32
						33
						34
						35
						36
						37
						38
321						39
						40

Schedule Page: 426 Line No.: 1 Column: a

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.

Schedule Page: 426 Line No.: 1 Column: f

For all of column F:
Base rating capacity reported unless otherwise noted.

Schedule Page: 426 Line No.: 7 Column: a

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 top rating capacity reported.

Schedule Page: 426 Line No.: 13 Column: a

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.

Schedule Page: 426 Line No.: 25 Column: a

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.

Schedule Page: 426.2 Line No.: 27 Column: a

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 top rating capacity reported.

Schedule Page: 426.2 Line No.: 38 Column: a

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.

Schedule Page: 426.3 Line No.: 15 Column: a

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.

Schedule Page: 426.3 Line No.: 29 Column: a

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.

Schedule Page: 426.4 Line No.: 17 Column: a

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.

Schedule Page: 426.5 Line No.: 13 Column: a

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.

Schedule Page: 426.6 Line No.: 7 Column: a

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.

Schedule Page: 426.6 Line No.: 32 Column: a

Idaho Power has 32% ownership interest in certain transmission related equipment located at Northwestern Energy's Mill Creek Station.

Schedule Page: 426.6 Line No.: 36 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership. 100% of the top rating capacity reported.

Schedule Page: 426.6 Line No.: 37 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership. 100% of the top rating capacity reported.

Schedule Page: 426.7 Line No.: 1 Column: a

Jointly owned with Portland General Electric, Power Resources Cooperative and BA Leasing BCS, LLC. Idaho Power has a 10% share of the jointly owned capacity. 100% of the top rating capacity is reported.

Schedule Page: 426.7 Line No.: 2 Column: a

Jointly owned with Portland General Electric, Power Resources Cooperative and BA Leasing BCS, LLC. Idaho Power has a 10% share of the jointly owned capacity. 100% of the top rating capacity is reported.

Schedule Page: 426.7 Line No.: 3 Column: a

Jointly owned with Portland General Electric, Power Resources Cooperative and BA Leasing BCS, LLC. Idaho Power has a 10% share of the jointly owned capacity. 100% of the top rating capacity is reported.

Schedule Page: 426.7 Line No.: 4 Column: a

Idaho Power has a 22% ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Burns station.

Schedule Page: 426.7 Line No.: 9 Column: a

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.

Schedule Page: 426.7 Line No.: 25 Column: a

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.

Schedule Page: 426.7 Line No.: 29 Column: a

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.

Schedule Page: 426.7 Line No.: 32 Column: a

Jointly owned with PacificCorp. Idaho Power has a 33.3% share of ownership. 100% of the top rating capacity is reported.

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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 Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account 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 Affiliate**			
21	Managerial Expenses	IDACORP, INC.	417420	439,832
22			922000	48,696
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

ANNUAL REPORT
OREGON SUPPLEMENT TO FERC FORM 1

for
MULTI-STATE ELECTRIC COMPANIES

INDEX

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STATE OF OREGON STATEMENT OF OPERATING INCOME FOR THE YEAR

Line No.	Account (a)	(Ref.) Page No. (b)	ELECTRIC UTILITY Current Year (c)	ELECTRIC UTILITY Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	2	$ 59,061,141	$ 57,999,613
3	Operating Expenses			
4	Operation Expenses (401)	8-11	38,818,292	35,936,127
5	Maintenance Expenses (402)	8-11	3,370,522	3,414,243
6	Depreciation Expense (403)	12	5,937,323	5,548,792
7	Amort. & Depl. of Utility Plant (404-405)	12	287,104	294,146
8	Amort. of Utility Plant Acq. Adj. (406)	12	-	-
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407-411)	12	(2,128)	(4,003)
10	Accretion Expense (411)	12	10,127	10,130
11	Amort. of Conversion Expenses (407)	12		
12	Taxes Other Than Income Taxes (408.1)	13	2,316,395	2,241,676
13	Regulatory Debits/Credits	14	167,068	82,611
14	Income Taxes - Federal (409.1)	14	(989,716)	(27,167)
15	- Other (409.1)	15	(982)	160,543
16	Provision for Deferred Inc. Taxes (410.1)	16-23	2,245,922	3,331,242
17	(Less) Provision for Deferred Income Taxes - Cr.(411.1)	16-23	(948,203)	(2,179,880)
18	Investment Tax Credit Adj. - Net (411.4)	24	13,162	20,588
19	(Less) Gains from Disp. of Utility Plant (411.6)			
20	Losses from Disp. of Utility Plant (411.7)			
21	TOTAL Utility Operating Expenses (Enter lines 4 thru 20)		51,224,886	48,829,048
22	Net Utility Operating Income (Total of line 2 less 20)		$ 7,836,254	$ 9,170,565

ELECTRIC OPERATING REVENUES (Account 400) - STATE OF OREGON

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
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.
3. If previous year (columns (c), (e) and (g), are not derived from previously reported figures, explain any inconsistencies in a footnote.
4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularl 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. Expla basis of classification in a footnote).
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.

Line No.	(a)	OPERATING REVENUES Amount for Current Year (b)	OPERATING REVENUES Amount for Previous Year (c)	MEGAWATT HOURS SOLD Amount for Current Year (d)	MEGAWATT HOURS SOLD Amount for Previous Year (e)	AVG NO OF CUSTOMERS PER MONTH Number for Current Year (f)	AVG NO OF CUSTOMERS PER MONTH Number for Previous Year (g)	Line No.
1	Sales of Electricity							1
2	(440) Residential Sales..	$ 18,068,244	$ 17,456,867	179,315	173,181	13,396	13,369	2
3	(442) Commercial and Industrial Sales							3
4	Small (or Commercial) (See Instr. 4) (1)...................	19,320,455	19,070,245	224,928	223,098	5,412	5,299	4
5	Large (or Industrial) (See Instr. 4) (2).......................	15,737,349	15,674,164	262,189	256,839	7	6	5
6	(444) Public Street and Highway Lighting..................	145,807	134,231	931	910	33	32	6
7	(445) Other Sales to Public Authorities………………							7
8	(446) Sales to Railroads and Railways......................							8
9	(448) Interdepartmental Sales....................................							9
10	TOTAL Sales to Ultimate Consumers....................	53,271,854*	52,335,507*	667,364 **	654,029	18,848	18,706	10
11	(447) Sales for Resale - Opportunity Non-Firm..........	1,176,057	1,409,856	55,333	57,245			11
12	TOTAL Sales of Electricity.....................................	-	53,745,363	722,696	711,274	18,848	18,706	12
13	(Less) (449.1) Provision for Rate Refunds.................	-	-					13
14	TOTAL Revenue Net of Provision for Refunds......	-	53,745,363					
15	Other Operating Revenues							
16	(450) Forfeited Discounts...							
17	(451) Miscellaneous Service Revenues.....................	82,758	83,132					
18	(453) Sales of Water and Water Power.....................							
19	(454) Rent from Electric Property...............................	710,042	1,138,991					
20	(455) Interdepartmental Rents……………………….							
21	(456) Other Electric Revenues...................................	3,820,429	3,032,127					
22								
23								
24								
25	TOTAL Other Operating Revenues........................	4,613,230	4,254,250					
26	TOTAL Electric Operating Revenues.....................	$ 4,613,230	$ 57,999,613					

* Includes $751,857 unbilled revenues.

** Includes 8475 MWH relating to unbilled revenues.

(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.

STATE OF OREGON SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the KWH of electricity sold, revenue, average number of customers, average KWH per customer, and average revenue KWH, excluding data for Sales for Resale which is reported on pages 310-311.

2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electri‹ Operating Revenues," page 301. 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 revenu account subheading.

3. Where the same customers are served under more than on‹ 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 (Thousands) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (cents) per KWH Sold (f)
1	440 - Residential Sales:					
2	01 - Residential	173,126	$ 17,497,030	13,396	12,924	10.11
3	03 - Residential-Mastered Metered					
4	05 - Residential - TOD					
5	15 - Dusk to Dawn customer Lighting	185	51,372			27.77
6	**Residential - Billed**	**173,311**	**17,548,402**	**13,396**	**12,937**	**10.13**
7	Residential - Unbilled	6,005	621,345			10.35
8	Bridger Depr & Boardman Decomm		(101,503)			
9	**Total 440**	**179,315**	**18,068,244**	**13,396**	**13,386**	**10.08**
10						
11	442 - Commercial and Industrial Sales:					
12	07 - General Service	18,272	1,941,058	2,518	7,257	10.62
13	09P - General Service	16,049	1,113,501	5	3,209,800	6.94
14	09S - General Service	113,881	9,010,192	892		
15	09T - General Service	2,614	177,681	1		
16	15 - Dusk to dawn customer lighting	253	57,277			22.64
17	19P - Uniform rate contracts	162,640	10,187,338	6	27,106,733	6.26
18	19S - Uniform rate contracts	0	0			
19	19T - Uniform rate contracts	99,404	5,801,935	1		
20	24S - Irrigation and soil drainage pumpi	71,529	6,872,350	1,994	35,865	9.61
21	40 - General Service	5	525	2	2,500	10.50
22	**Commercial & Industrial - Billed**	**484,648**	**35,161,857**	**5,419**	**89,429**	**7.26**
23	Commercial & Industrial - Unbilled	2,469	130,110			5.27
24	Bridger Depr & Boardman Decomm		(234,164)			
25	**Total 442**	**487,117**	**35,057,803**	**5,419**	**89,885**	**7.20**
26						
27						
28	444 - Public Street and Highway Lighting:					
29	40 - General Service					
30	41 - Municipal street lighting	908	143,719	25	36,320	15.83
31	42 - Municipal traffic control signal lighti	22	2,088	8	2,750	9.49
32	**Public Street & Highway lighting billed**	**930**	**145,807**	**33**	**28,182**	**15.68**
33	Public St & Highway lighting-unbilled	1	402			
34	Bridger Depr & Boardman Decomm		(402)			
35	**Total 444**	**931**	**145,807**	**33**	**28,224**	**15.65**
36						
37						
38						
39						
40						
41	Total Billed	658,888	52,519,997	18,848	34,957	7.97
42	Total Unbilled Rev. (See Instr. 6)	8,475	751,857			
43	TOTAL	667,364	53,271,854	18,848	34,957	7.97

ALLOCATED SALES FOR RESALE (Account 447) - STATE OF OREGON

1. Report sales during the year to other electric utilities and to cities or other public authorities for distribution to ultimate consumers.

2. Provide in column (a) subheadings and classify sales as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Municipalities, (4) Cooperatives, and (5) Other Public Authorities. For each sale designate statistical classification in column (b) using the following codes: FP, firm power supplying total system requirements of customer or total requirements at a specific point of delivery; FP(C), firm power supplying total system requirements of customer or total requirements at a specific point of delivery with credit allowed customer for available standby; FP(P), firm power supplementing customer's own generation or other purchases; DP, dump power; O, other. Describe in a footnote the nature of any sales classified as Other Power. Place an "x" in column (c) if sales involves export across a state line. Group together sales coded "x" in column (c) by state (or county) of origin identified in column (e), providing a subtotal for each state (or county) of delivery in columns (L) and (p).

Line No.	Sales To	Stat. Class.	Export Across State Lines	FERC Rate Sch. No.	Point of Delivery (State or County)	Station Ownership	MW or MVa of Demand (Specify which)		
							Contract Demand	Average Monthly Maximum Demand	Annual Maximum Demand
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1									
2									
3	Various Utilities								
4									
5									
6			0						
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									

ALLOCATED SALES FOR RESALE (Account 447) (Continued) - STATE OF OREGON

3. Report separately firm, dump, and other power sold to the same utility.

4. If delivery is made at a substation, indicate ownership in column (f), using the following codes: RS, respondent owned or leased; CS, customer owned or leased.

5. If a fixed number of megawatts of maximum demand is specified in the power contract as a basis of billings to the customer, enter this number in column (g). Base the number of megawatts of maximum demand entered in columns (h) and (i) on actual monthly readings. Furnish these figures whether or not they are used in the determination of demand charges. Show in column (j) type of demand reading (i.e., instantaneous, 15, 30, or 60 minutes integrated).

6. For column (l) enter the number of megawatt hours shown on the bills rendered to the purchasers.
7. Explain in a footnote any amounts entered in column (o), such as fuel or other adjustments.
8. If a contract covers several points of delivery and small amounts of electric energy are delivered at each point, such sales may be grouped.

Type of Demand Reading (j)	Voltage at Which Delivered (k)	Megawatt Hours (l)	REVENUE Demand Charges (m)	Energy (n)	Other Charges (o)	Total (p)	Line No.
							1
							2
				1,176,057		$ 1,176,057	3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
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							29

SALES TO RAILROADS AND RAILWAYS AND INTERDEPARTMENTAL SALES (Accounts 446, 448)

1. Report particulars concerning sales included in Accounts 446 and 448.
2. For Sales to Railroads and Railways, Account 446, give name of railroad or railway in addition to other required information. If contract covers several points of delivery and small amounts of electricity are delivered at each point, such sales may be grouped.
3. For Interdepartmental Sales, Account 448, give name of other department and basis of charge to other department in addition to other required information.
4. Designate associated companies.
5. Provide subheading and total for each account.

Line No.	Item (a)	Point of Delivery (b)	Kilowatt-hours (c)	Revenue (d)	Revenue per KWH (e)
1	None				
2					
3					
4					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19			0		
20					

RENT FROM ELECTRIC PROPERTY AND INTERDEPARTMENTAL RENTS (Accounts 454, 455)

1. Report particulars concerning rents received included in Accounts 454 and 455.
2. Minor rents may be grouped by classes.
3. If rents are included which were arrived at under an arrangement for apportioning expenses of a joint facility, whereby the amount included in this account represents profit or return on property, depreciation, and taxes, give particulars and the basis of apportionment of such charges to Account 454 or 455.
4. Designate if lessee is an associated company.
5. Provide a subheading and total for each account.

Line No.	Name of Lessee or Department (a)	Description of Property (b)	Amount of Revenue For Year (c)
21	Various	Substation Equipment Rental	$ 121,122
22			
23	"	Transformer Rentals - Dist	700
24			
25	"	Line Rentals	10,570
26			
27	"	Cogeneration	51,630
28			
29	"	Pole Attachments	103,809
30			
31	"	Facilities Charges	394,308
32			
33	"	Other Rentals	25,716
34			
35	"	Water Lease	2,187
36			
37	"		
38	Total Account 454		$ 710,042

ALLOCATED SALES OF WATER AND WATER FOR POWER (Account 453) - OREGON

1. Report below the information called for concerning revenues derived during the year from sales to others of water or water power.
2. In column (c) show the name of the power development of the respondent supplying the water or water power sold.
3. Designate associated companies.

Line No.	Name of Purchaser (a)	Purpose for which Water was Used (b)	Power Plant Development (c)	Amount of Revenue for Year (d)
1	None			
2				
3		TOTAL		

MISCELLANEOUS SERVICE REVENUES AND OTHER ELECTRIC REVENUES (Accounts 451, 456)

1. Report particulars concerning miscellaneous service revenues and other electric revenues derived from electric utility operations during year. Report separately in this schedule the total revenues from operation of fish and wildlife and recreation facilities, regardles of whether such facilities are operated by company or by contract concessionaires. Provide a subheading and total for each account. For account 456, list first revenues realized through Research and Development ventures, see account 456.
2. Designate associated companies.
3. Minor items may be grouped by classes.

Line No.	Name of Company and Description of Service	Amount of Revenue for Year (b)
4	Account 451	
5		
6	Miscellaneous Service Revenues........ 0	$ 82,758
7		
8	Account 456	
9		
10	Transmission for Others - Network........	$ 440,791
11	Transmission - Point-to-Point and Other........	916,879
12	Photovoltaic Station Service........	-
13	DSM Rider Funds........	2,462,482
14	Sierra Pacific Usage Charge........	-
15	Antelope........	-
16	Miscellaneous........	277
17		
18		
19		
20	Total Account 456........	$ 3,820,429
21		
22		
23		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
	ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - OREGON		
	If the amount for previous year is not derived from previously reported figures, explain in footnotes.		
1	(1) POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	$ 50,046	$ 52,912
5	(501) Fuel	6,424,516	5,992,594
6	(502) Steam Expenses	418,593	446,940
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	68,406	57,612
10	(506) Miscellaneous Steam Power Expenses	392,871	274,292
11	(507) Rents	8,928	17,750
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	7,363,361	6,842,100
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	4,323	5,217
16	(511) Maintenance of Structures	22,807	36,075
17	(512) Maintenance of Boiler Plant	665,523	632,714
18	(513) Maintenance of Electric Plant	240,324	247,057
19	(514) Maintenance of Miscellaneous Steam Plant	277,915	284,439
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	1,210,893	1,205,503
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)	8,574,254	8,047,603
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 and 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	246,514	240,006
45	(536) Water for Power	260,228	372,651
46	(537) Hydraulic Expenses	633,417	612,487
47	(538) Electric Expenses	74,308	68,262
48	(539) Miscellaneous Hydraulic Power Generation Expenses	246,142	233,169
49	(540) Rents	10,164	9,666
50	TOTAL Operation (Enter Total of lines 44 thru 49)	1,470,774	1,536,241

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
	ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON		
	If the amount for previous year is not derived from previously reported figures, explain in footnotes.		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$ 5,041	$ 4,944
54	(542) Maintenance of Structures	52,620	46,035
55	(543) Maintenance of Reservoirs, Dams, and Waterways	28,431	23,642
56	(544) Maintenance of Electric Plant	97,479	113,866
57	(545) Maintenance of Miscellaneous Hydraulic Plant	101,285	117,506
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	284,855	305,992
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)	1,755,629	1,842,234
61	Operation		
62	(546) Operation Supervision and Engineering	31,892	26,567
63	(547) Fuel	1,950,480	2,507,960
64	(548) Generation Expenses	185,587	198,529
65	(549) Miscellaneous Other Power Generation Expenses	34,853	38,388
66	(550) Rents	-	-
67	TOTAL Operation (Enter Total of lines 62 thru 66)	2,202,813	2,771,444
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	-	-
70	(552) Maintenance of Structures	17,310	14,942
71	(553) Maintenance of Generating and Electric Plant	5,682	3,125
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	119,395	52,186
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	142,387	70,253
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	2,345,200	2,841,698
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	11,198,287	9,919,405
77	(556) System Control and Load Dispatching	116	100
78	(557) Other Expenses	2,679,898	2,452,085
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	13,878,301	12,371,590
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	26,553,383	25,103,124
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	127,768	170,284
84	(561) Load Dispatching	202,825	120,729
85	(562) Station Expenses	114,125	108,395
86	(563) Overhead Line Expenses	41,263	39,841
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	259,200	286,612
89	(566) Miscellaneous Transmission Expenses	323	97
90	(567) Rents	179,106	126,995
91	TOTAL Operation (Enter Total of lines 83 thru 90)	924,610	852,955
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	7,348	6,465
94	(569) Maintenance of Structures	40,689	38,324
95	(570) Maintenance of Station Equipment	96,054	135,275
96	(571) Maintenance of Overhead Lines	49,028	120,896
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	-	-
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	193,119	300,960
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	1,117,729	1,153,915
102	Operation		
103	(580) Operation Supervision and Engineering	182,004	186,340

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON			
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)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(581) Load Dispatching	$ 162,537	$ 147,231
106	(582) Station Expenses	54,769	60,472
107	(583) Overhead Line Expenses	264,532	291,515
108	(584) Underground Line Expenses	42,729	39,148
109	(585) Street Lighting and Signal System Expenses	3,834	4,060
110	(586) Meter Expenses	164,273	163,022
111	(587) Customer Installations Expenses	67,852	59,638
112	(588) Miscellaneous Distribution Expenses	323,796	262,440
113	(589) Rents	13,138	11,385
114	TOTAL Operation (Enter Total of lines 103 thru 113)	1,279,465	1,225,252
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	(66,948)	462
117	(591) Maintenance of Structures	-	-
118	(592) Maintenance of Station Equipment	137,242	163,900
119	(593) Maintenance of Overhead Lines	1,098,593	1,043,477
120	(594) Maintenance of Underground Lines	12,064	8,190
121	(595) Maintenance of Line Transformers	1,154	1,383
122	(596) Maintenance of Street Lighting and Signal Systems	27,314	22,475
123	(597) Maintenance of Meters	30,424	26,251
124	(598) Maintenance of Miscellaneous Distribution Plant	28,728	22,027
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	1,268,572	1,288,164
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	2,548,037	2,513,415
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	32,851	17,671
130	(902) Meter Reading Expenses	357,860	78,963
131	(903) Customer Records and Collection Expenses	518,428	555,097
132	(904) Uncollectible Accounts	228,265	191,185
133	(905) Miscellaneous Customer Accounts Expenses	(30)	16
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	1,137,373	842,932
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	52,431	48,872
138	(908) Customer Assistance Expenses	2,713,679	2,275,477
139	(909) Informational and Instructional Expenses	34,997	15,192
140	(910) Miscellaneous Customer Service and Informational Expenses	29,646	44,303
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140)	2,830,753	2,383,844
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		
145	(912) Demonstrating and Selling Expenses	1	3639
146	(913) Advertising Expenses		
147	(916) Miscellaneous Sales Expenses		
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	1	3,639
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	3,895,929	3,255,870
152	(921) Office Supplies and Expenses	706,857	655,957
153	(922) Administrative Expenses Transferred-Credit	(1,616,903)	(1,163,996)

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON

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)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$ 393,636	$ 364,427
156	(924) Property Insurance	143,663	140,544
157	(925) Injuries and Damages	286,704	296,110
158	(926) Employee Pensions and Benefits	3,419,491	3,004,798
159	(927) Franchise Requirements	-	-
160	(928) Regulatory Commission Expenses	303,647	282,156
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	27,851	27,544
163	(930.2) Miscellaneous General Expenses	169,967	242,637
164	(931) Rents	-	84
165	TOTAL Operation (Enter Total of lines 151 thru 164)	7,730,842	7,106,131
166	Maintenance		
167	(935) Maintenance of General Plant	270,696	243,371
168	TOTAL Administrative and General Expenses (Enter Total of lines 165 thru 167)	8,001,539	7,349,501
169	TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 80, 100, 126, 134, 141, 148, and 168)	$42,188,814	$ 39,350,370

SUMMARY OF ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - OREGON

Line No.	Functional Classification (a)	Operation (b)	Maintenance (c)	Total (d)
170	Power Production Expenses			
171	Electric Generation:			
172	Steam power	$ 7,363,361	$ 1,210,893	$ 8,574,254
173	Nuclear power			
174	Hydraulic - Conventional	1,470,774	284,855	1,755,629
175	Hydraulic - Pumped Storage			
176	Other power	2,202,813	142,387	2,345,200
	Other Power Supply Expenses	13,878,301	-	13,878,301
177	Total Power Production Expenses	24,915,247	1,638,135	26,553,383
178	Transmission Expenses	924,610	193,119	1,117,729
179	Distribution Expenses	1,279,465	1,268,572	2,548,037
180	Customer Accounts Expenses	1,137,373	-	1,137,373
181	Customer Service and Informational Expenses	2,830,753	-	2,830,753
182	Sales Expenses	-	-	-
183	Administrative and General Expenses	7,730,842	270,696	8,001,539
184	Total Electric Operation and Maintenance Expenses	$ 38,818,291	$ 3,370,522	$ 42,188,813

ALLOCATED DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405) - OREGON
(Except amortization of acquistion adjustments)

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited-Term Electric Plant (Account 404) (c)	Amortization of Other Electric Plant (Acct. 405) (d)	Total (e)
1	Intangible Plant	$ -	$ 287,104		$ 287,104
2	Steam Production Plant	1,165,404	-		1,165,404
3	Nuclear Production Plant				-
4	Hydraulic Production Plant - Conventional	645,856	-		645,856
5	Hydraulic Production Plant - Pumped Storage				
6	Other Production Plant	712,231	-		712,231
7	Transmission Plant	957,146	-		957,146
8	Distribution Plant	1,955,533	-		1,955,533
9	General Plant	483,042	-		483,042
10	Depreciation on Disallowed Costs	(12,957)	-		(12,957)
11	Boardman ARO Depreciation	31,069			31,069
12	ARO Accretion	10,127			10,127
13	TOTAL	$ 5,947,450	$ 287,104		$ 6,234,554

B. OTHER AMORTIZATION

Describe briefly the nature of each transaction giving rise to amortization included in Account 406, Amortization of Utility Plant Acquisition Adjustments, or Account 407, Amortizatior 0
information for each transaction, as well as providing a total for each account.

Nature of Transaction	OPUC Number	Amortization Period	Amount
Account 406			
Amortization of Electric Plant Acquisition Adjustment - Prairie Power			0
Account 411			
411.6			$ -
411.7			-
411.8			(2,128)
			$ (2,128)

ALLOCATED TAXES, OTHER THAN INCOME TAXES (ACCOUNT 408.1) - OREGON

	KIND OF TAX	Amount
1	Federal Taxes:	
2	FICA	$ 736,451
3	FUTA	6,363
4	Less: Payroll Deduction and Loading	(772,553)
5	State Taxes:	
6	Ad Valorem	1,215,135
7	Licenses - Hydro Projects	209
8	Regulatory Commission Fees	224,995
9	Franchise Taxes	820,300
10	State Unemployment Taxes	29,738
11	Hydro Generation KWH Tax	55,757
12	Canada Sales Tax	0
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23	TOTAL (Must agree with page 1, line 12.)	2,316,395

CALCULATION OF CURRENT FEDERAL INCOME TAX EXPENSE - Account 409.1

1. Report amounts used to derive current Federal income tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).

2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.

3. Current tax expense on this schedule must match the amount reported on page 1, line 12 of this report. Separately identify adjustments arising from revisions of prior year accruals.

4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	Particulars (Details) (a)	Amount (b)
1	Electric Operating Revenues	$ 59,061,141
2	Operations and Maintenance Expenses	42,188,814
3	Taxes Other Than Income	2,316,395
4	Regulatory Debits/Credits	167,068
5	State Income (Excise) Tax	8,023
6	Interest	3,994,372
7	Federal Income Tax Depreciation	5,937,323
8	Other Line items to Derive Taxable Income	10,127
9	Amortization of Limited-Term Plant	284,976
10		
11		
12		
13		0
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24	Federal Tax Net Income	$ 4,154,041
25		
26		
27	Show Computation of Tax:	
28		
29	Federal Income Tax @ 35%	$ 1,453,914
30	FIN 48 Adjustment	-
31	Prior Years' Tax Adjustment	27,569
32	Total Federal Income Tax Before Other Adjustments	1,481,484
33		
34	Other Tax Adjustments	
35	Allowance for AFUDC	$ 1,390,982
36	Income Tax Adjustments	(8,451,552)
37	Federal Tax on Other Tax Adj @ 35%	(2,471,200)
38		
39	Total Federal Income Tax	$ (989,716)

CALCULATION OF CURRENT STATE INCOME (EXCISE) TAX EXPENSE - Account 409.1

1. Report amounts used to derive current state income (excise) tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).

2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.

3. Current tax expense on this schedule must match the amount reported on page 1, line 15 of this report. Separately identify adjustments arising from revisions of prior year accruals.

4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	Particulars (Details) (a)	Amount (b)
1	Electric Operating Revenues	$ 59,061,141
2	Operations and Maintenance Expenses	42,188,814
3	Taxes Other Than Income	2,316,395
4	Regulatory Debits/Credits	167,068
5	Interest	3,994,372
6	State Income (Excise) Tax Depreciation	5,937,323
7		
8	Other Line Items to Derive Taxable Income	
9	Amortization of Limited-Term Plant	284,976
	ARO Accretion Expense	10,127
10	Income Tax Adjustments	8,780,750
11	Allowance for AFUDC	(1,390,982)
12	IERCO Taxable Income	(852,212)
13		
14	State Tax Net Income	$ (2,375,492)
15		
16		
17		
18		
19	Show Computation of Tax:	
20		
21	State Taxes	8,023
22	Add: FIN 48 Adjustment	-
23	Prior Period Adjustment	(9,006)
24		
25		
26	Total Oregon State Tax	$ (982)

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. In the space provided:
(a) identfy, by amount and classification, significant items for which deferred taxes are being provided.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Electric			
2	Emission Allowances	$	$ -	$ -
3	Advances for Construction		0	(5,911)
4	Other Operating (See Note 1)		59,044	(335,435)
5				
6	Non-Operating			
7				
8				
9	Total Electric	$	$ 59,044	$ (341,346)
10	Gas	$	$	$
11				
12				
13	Other			
14	Total Gas	$	$	$
15	Other Non-Electric	$	$	$
16	Total (Account 190)	$	$ 59,044	$ (341,346)
17	Classification of TOTALS	0		
18	Federal Income Tax	$	$	$
19	State Income Tax	$	$	$
20	Local Income Tax	$	$	$
	Note 1:			
	Rate Case Disallowance		3,409	0
	Executive Deferred Compensation		0	0
	Executive Deferred Compensation Long-Term		0	0
	SFAS 112 - Post Retirement Benefits		0	(2,332)
	Non-VEBA Pension and Benefits		4,207	0
	FAS 123R - Stock Based Compensation		0	(1,404)
	Provision for Rate Refunds		0	0
	Revenue Sharing		36,354	0
	Montana NOL		0	0
	Oregon NOL		0	0
	Federal NOL		0	0
	Valmy Union Pacific Contract		0	0
	Deferred Idaho ITC		15,647	(77,384)
	VEBA - Post Retiree Benefits		154	(12,055)
	Bridger Revenue Deferral		0	(3,703)
	AFUDC Hells Canyon Relicensing		0	(178,690)
	Reg Liability		0	0
	Reg Asset		0	0
	Boardman Decommission		0	0
	USBR-American Falls O&M Costs Settlement		402	0
	Oregon Pension Expense		0	(15,142)
	Incentive Deferral - Profit Sharing not in rates		0	(33,115)
	M&E Reserve		0	0
	Asset Retirement Obligation (ARO)		0	(10,957)
	Deferred GBC Federal		(1,129)	0
	Retention Pay Accrual		0	(654)
	Total	$	$ 59,044	$ (335,435)

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (Continued)

(b) indicate insignificant amounts under OTHER.
3. Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits		Balance at	Line
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	End of Year (k)	No.
							1
$	$		$		$	$	2
							3
							4
							5
4,646	(55,549)						6
							7
							8
$ 4,646	$ (55,549)		$		$	$	9
$	$		$		$	$	10
							11
							12
							13
$	$		$		$	$	14
$ -			$		$	$	15
$ 4,646	$ (55,549)		$		$	$	16
							17
$	$		$		$	$	18
$	$		$		$	$	19
$	$		$		$	$	20
$ -	$ -						

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. In the space provided furnish explanations, including the following in columnar order:
(a) State each certification number with a brief description of property.
(b) Total and amortizable cost of such property.
(c) Date amortization for tax purposes commenced.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Accelerated Amortization (Account 281)	NONE		
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other: Accelerated Amortization			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other	0		
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16	Other (Specify)			
17	TOTAL (Account 281)(Enter Total of 8, 15, and 16)		$ -	$ -
18				
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

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

(d) "Normal" depreciation rate used in computing the deferred tax.

(e) Tax rate used to originally defer amounts and the tax rate used during the current year to amortize previous deferrals.

3. Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.

4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Debits Acct. No. (g)	Debits Amount (h)	Credits Acct. No. (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
$ -	$ -						17
							18
							19
							20
							21

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. In the space provided furnish below explanations,including the following:
State the general method or methods of liberalized depreciation being used (sum-of-year digits, declining balance, etc.,) estimated lives i.e. useful life, guideline life, guideline class life, etc., and classes of plant to

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Account 282			
2	Electric		$ 1,685,637	$ (558,689)
3	Gas			
4	Other (Define)			
5	TOTAL (Enter Total of lines 2 thru 4)		1,685,637	(558,689)
6	Other (Specify)			
7	FERC Jurisdictional Deferral			
8	Non-Utility Property			
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)		$ 1,685,637	$ (558,689)
10	Classification of TOTAL			
11	Federal Income Tax	0		
12	State Income Tax			
13	Local Income Tax			
	Line 2:			
	Depr Federal Adj		1,677,258	(531,411)
	Intangible Asset - Labor Deductions		(28,011)	-
	N Valmy Partnership Capitalized Items		-	(2,744)
	CIAC as Taxable Income		15,817	(20,292)
	FERC Juris-S Georgia-Acct 282 Def only		-	-
	Engineering Fees		0	(4,243)
	Software Costs		20,573	-
	Total		1,685,637	(558,689)

ACCUMULATED DEFERRED INCOME TAXES-OTHER PROPERTY (Account 282) (Continued)

which each method is being applied and date method was adopted.

3.Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.

4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	(k)	
							1
$ -	$ -				$ -		2
							3
							4
0	0				0		5
							6
							7
$ -	$ -						8
$ -	$ -				$ -		9
							10
							11
							12
							13

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. In the space provided below include amounts relating to insignificant items under Other.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited (Account 410.1) (c)	CHANGES DURING YEAR: Amounts Credited (Account 411.1) (d)
1	Account 283			
2	Electric (See Note 1)		501,240	(48,167)
3				
4	Total Electric		501,240	(48,167)
5				
6				
7	Other (See Note 2)			
8				
9				
10	Total (Account 283) (Enter Total of lines 4 - 9)		$ 501,240	$ (48,167)
11	Classification of Total:			
12	Federal Income Tax			
13	State Income Tax			
14	Local Income Tax			
	Note 1:			
	Oregon PCAM	0	83	(26,082)
	FERC Grid West Expense		0	0
	PCA		102,251	0
	Conservation Programs		12,126	0
	Oregon Excess Power Supply Costs		0	(83)
	OATT Revenue Deficiency		0	0
	Emission Allowances		0	(209)
	Fixed Cost Adjustment (FCA)		87,733	(0)
	OPUC Grid West Loans		0	(27)
	Intervenor Funding Orders		1,151	0
	Bonus Deferral		0	0
	Prepaid Credit Facility		8,031	0
	Delivery Accruals		0	0
	REC Sales		0	(20,403)
	Pension Expense		268,382	0
	LIDAR Surveys Deferral		0	(502)
	Bennett Mtn Maintenance Deferral		0	(862)
	Custom Efficiency Incentive Payment		0	0
	Reg Liability		0	0
	Reg Asset		0	0
	Siemens LTP Contract		1,092	0
	Boardman Decommission		2,075	0
	PS&I Costs		7,675	0
	Royalty Income		10,643	0
	Total		501,240	(48,167)
	Note 2:			
	Advance Coal Royalties			
	Oregon Non-Operating Property Tax Adj			
	Unrealized Gain/Loss from SMSP			
	Total			

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283) (Continued)

3. Beginning balances may be omitted if not readily available. Report electric utility deferred taxes only.

4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Debits Acct. No. (g)	Debits Amount (h)	Credits Acct. No. (i)	Credits Amount (j)	(k)	
							1
0	0						2
							3
-	-		-		-		4
							5
							6
183	(12,353)						7
							8
							9
$ 183	$ (12,353)		$ -		$ -		10
							11
							12
							13
							14
0	0						
183	(10,643)						
0	0						
0	(1,710)						
183	(12,353)						

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. 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: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)	Balance at End Year (h)	Average Period of Allocation To Income (i)
1	Electric Utility								
2	3%								
3	4%								
4	7%								
5	10%								
6									
7									
8									
9	TOTAL		411.4	$ 139,299	411.4	$ (126,137)			
10									
11	Other (List separately								
12	and show 3%, 4%, 7%,								
13									
14									
15									
16									
17									
18			0						
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (Classified)..	$ 501,325,723	$ 501,325,723				
4	Property Under Capital Leases....................................						
5	Plant Purchased or Sold...						
6	Completed Construction not Classified........................						
7	Experimental Plant Unclassified..................................						
8	TOTAL (Enter Total of lines 3 thru 7)..........................	$ 501,325,723	$ 501,325,723				
9	Leased to Others..						
10	Held for Future Use..	$ 89,977	$ 89,977				
11	Construction Work in Progress....................................	$ 42,676,042	$ 42,676,042				
12	Acquisition Adjustments..						
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)......	$ 544,091,743	$ 544,091,743				
14	Accum. Prov. for Depr., Amort., & Depl........................	NOT AVAILABLE					
15	Net Utility Plant (Enter Total of line 13 less 14)…………	$ 544,091,743	$ 544,091,743				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service						
18	Depreciation...	0					
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights...						
20	Amort. of Underground Storage Land and Land Rights						
21	Amort. of Other Utility Plant...						
22	TOTAL In Service (Enter total of lines 18 thru 21)........						
23	Leased to Others						
24	Depreciation...						
25	Amortization and Depletion..						
26	TOTAL Leased to Others (Enter Total of lines 24 and 2						
27	Held for Future Use						
28	Depreciation...						
29	Amortization..						
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)..						
31	Abandonment of Leases (Natural Gas)..........................						
32	Amort. of Plant Acquisition Adj......................................						
33	TOTAL Accumulated Provisions (Should agree with li 14 above) (Enter Total of lines 22,26,30,31,and 32)....						

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (d) as appropriate.

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) 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.

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. INTANGIBLE PLANT								1
2	(301) Organization	$ 1,230	$	$	$	$	$ 1,230	(301)	2
3	(302) Franchises and Consents	241,023					241,023	(302)	3
4	(303) Miscellaneous Intangible Plant							(303)	4
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	242,253	0	0	0	0	242,253		5
6	2. PRODUCTION PLANT								6
7	A. Steam Production Plant								7
8	(310) Land and Land Rights	106,610					106,610	(310)	8
9	(311) Structures and Improvements	12,492,016	135,342				12,627,358	(311)	9
10	(312) Boiler Plant Equipment	43,633,060	108,076	(19,477)			43,721,658	(312)	10
11	(313) Engines and Engine Driven Generators	0					0	(313)	11
12	(314) Turbogenerator Units	13,570,761	(1,140)				13,569,621	(314)	12
13	(315) Accessory Electric Equipment	4,670,665	(64,072)				4,606,593	(315)	13
14	(316) Misc. Power Plant Equipment	1,738,813	72,725	(14,585)			1,796,953	(316)	14
15	(317) Asset Retirement Costs for Steam Production	0	949,333				949,333	(317)	15
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	76,211,924	1,200,264	(34,063)	0	0	77,378,126		16
17	B. Nuclear Production Plant								17
18	(320) Land and Land Rights	0					0	(320)	18
19	(321) Structures and Improvements	0					0	(321)	19
20	(322) Reactor Plant Equipment	0					0	(322)	20
21	(323) Turbogenerator Units	0					0	(323)	21
22	(324) Accessory Electric Equipment	0					0	(324)	22
23	(325) Misc. Power Plant Equipment	0					0	(325)	23
24	(326) Asset Retirement Csts for Nuclear Productions	0					0	(326)	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	0	0	0	0	0	0		25
26	C. Hydraulic Production Plant								26
27	(330) Land and Land Rights	11,181,675	8,928				11,190,603	(330)	27
28	(331) Structures and Improvements	19,784,527	1,067,645				20,852,172	(331)	28
29	(332) Reservoirs, Dams, and Waterways	92,078,355	21,770				92,100,125	(332)	29
30	(333) Water Wheels, Turbines, and Generators	23,601,027	628,540				24,229,567	(333)	30
31	(334) Accessory Electric Equipment	12,644,211	(238,665)	(89,918)			12,315,628	(334)	31
32	(335) Misc. Power Plant Equipment	4,393,730	358,654	(2,557)			4,749,827	(335)	32
33	(336) Roads, Railroads, and Bridges	1,388,105	0				1,388,105	(336)	33
34	(337) Asset Retirement Costs for Hydraulic Production	0	-				0	(337)	34
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	165,071,630	1,846,872	(92,475)		0	166,826,027		35

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (d) as appropriate.

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) 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.

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
36	D. Other Production Plant								36
37	(340) Land and Land Rights	$	$	$	$	$	$	(340)	37
38	(341) Structures and Improvements	0					0	(341)	38
39	(342) Fuel Holders, Products and Accessories	0					0	(342)	39
40	(343) Prime Movers	0					0	(343)	40
41	(344) Generators	0					0	(344)	41
42	(345) Accessory Electric Equipment	0					0	(345)	42
43	(346) Misc. Power Plant Equipment	0					0	(346)	43
44	(347) Asset Retirement Costs for Hydraulic Production	0					0	(347)	44
45	TOTAL Other Production Plant (Enter Total of lines 36 thru 44)	0	0	0	0	0	0		45
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	241,283,554	3,047,136	(126,538)	0	0	244,204,152		46
47	3. TRANSMISSION PLANT								47
48	(350) Land and Land Rights	4,689,563	$ 80,737				4,770,300	(350)	48
49	(352) Structures and Improvements	7,307,591	71,424	(1,438)			7,377,577	(352)	49
50	(353) Station Equipment	37,356,242	247,298	(252,251)			37,351,288	(353)	50
51	(354) Towers and Fixtures	24,620,204	1,116,044				25,736,248	(354)	51
52	(355) Poles and Fixtures	30,829,814	3,968,070	(87,649)			34,710,235	(355)	52
53	(356) Overhead Conductors and Devices	27,287,918	2,099,538	(110,581)			29,276,876	(356)	53
54	(357) Underground Conduit	0	0				0	(357)	54
55	(358) Underground Conductors and Devices	0	0				0	(358)	55
56	(359) Roads and Trails	48,567	0				48,567	(359)	56
57	(359.1) Asset Retirement Costs for Transmission Plant	0	-				0	(359.1)	57
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	132,139,898	7,583,111	(451,919)	0	0	139,271,091		58
59	4. DISTRIBUTION PLANT								59
60	(360) Land and Land Rights	149,236	$ 8,544				157,780	(360)	60
61	(361) Structures and Improvements	1,417,122	457,232	(7,377)			1,866,978	(361)	61
62	(362) Station Equipment	10,244,927	(1,181,541)	(718,663)			8,344,724	(362)	62
63	(363) Storage Battery Equipment	0					0	(363)	63
64	(364) Poles, Towers, and Fixtures	18,842,485	796,763	(93,527)			19,545,721	(364)	64
65	(365) Overhead Conductors and Devices	8,804,153	106,467	(35,231)			8,875,388	(365)	65
66	(366) Underground Conduit	650,604	34,498	(2,031)			683,071	(366)	66
67	(367) Underground Conductors and Devices	3,122,355	273,353	(3,479)			3,392,229	(367)	67
68	(368) Line Transformers	46,652,346	2,134,855	(69,029)			48,718,172	(368)	68
69	(369) Services	2,871,692	41,446	(38,769)			2,874,370	(369)	69
70	(370) Meters	7,712,550	381,448	(170,929)			7,923,068	(370)	70
71	(371) Installations on Customer Premises	224,697	7,332	(4,008)			228,022	(371)	71
72	(372) Leased Property on Customer Premises	0	0				0	(372)	72
73	(373) Street Lighting and Signal Systems	209,733	1,285	(2,181)			208,837	(373)	73
74	(374) Asset Retirement Cost for Distribution Plant	0	0				0	(374)	74
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	100,901,900	3,061,683	(1,145,222)	0	0	102,818,361		75

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (d) as appropriate.

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) 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.

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
76	5. GENERAL PLANT								76
77	(389) Land and Land Rights	8,243					8,243	(389)	77
78	(390) Structures and Improvements	495,898					495,898	(390)	78
79	(391) Office Furniture and Equipment	178,075	35,812	(878)			213,009	(391)	79
80	(392) Transportation Equipment	2,957,963	149,929	(168,835)			2,939,057	(392)	80
81	(393) Stores Equipment	0					0	(393)	81
82	(394) Tools, Shop and Garage Equipment	4,129					4,129	(394)	82
83	(395) Laboratory Equipment	60,990		(7,658)			53,332	(395)	83
84	(396) Power Operated Equipment	1,845,780	104,064	(8,821)			1,941,023	(396)	84
85	(397) Communication Equipment	4,473,480	801,179	(595,235)			4,679,424	(397)	85
86	(398) Miscellaneous Equipment	19,177	5,144				24,321	(398)	86
87	SUBTOTAL (Enter Total of lines 77 thru 86)	10,043,734	1,096,129	(781,428)	0	0	10,358,435		87
88	(399) Other Tangible Property *	0					0	(399)	88
90	(399.1) Asset Retirement Costs for General Plant	0					0	(399.1)	90
91	TOTAL General Plant (Enter Total of lines 87 thru 90)	10,043,734			0	0	10,358,435		91
92	TOTAL (Accounts 101 and 106)	484,611,339			0	0	496,894,292		92
93	(102) Electric Plant Purchased **								93
94	(Less) (102) Electric Plant Sold **								94
95	(103) Experimental Electric Plant Unclassified								95
96	TOTAL Electric Plant in Service	$ 484,611,339	$	$	$	$	$ 496,894,292		96

* State the nature and use of plant included in this account and if substantial in amount submit a supplementary schedule showing subaccount classification of such plant conforming to the requirements of this schedule.

** For each amount comprising the reported balance and charges 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.

NOTE

Completed Construction Not Classified, Account 106, shall be classified in this schedule according to prescribed accounts, on an estimated basis if necessary, and the entries included in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (c). Likewise, if respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, a tentative distribution of such retirements, on an estimated basis with appropriate contra entry to the account for accumulated depreciation provision, shall be included in column (d). Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach an insert page 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.

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

1. Report below the information called for concerning accumulated provision for depreciation of electric utility plant.
2. Explain any important adjustments during year.
3. Explain any difference between the amount for book cost of plant retired, line.., column (c), and that reported in the schedule for electric plant in service, pages 401-403, column (d) exclusive of retirements of nondepreciable property.
4. The provisions of account 108 in the Uniform System of Accounts contemplate 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, preliminary closing entries should be made to tentatively functionalize the book cost of the plant retired. In addition, all cost included in retirement work in progress at year end should be included in the appropriate functional classifications.
5. Show separately interest credits under a sinking fund or similar method of depreciation accounting.
6. In section B show the amounts applicable to prescribed functional classifications.

Section A. Balances and Changes During Year

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)
1	Balance Beginning of Year......				
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense......				
4	(413) Exp. of Elec. Plt. Leas. to Others......				
5	Transportation Expenses-Clearing......	**INFORMATION NOT AVAILABLE BY STATE ON A SITUS BASIS.**			
6	Other Clearing Accounts......				
7	Other Accounts (Specify):				
8					
9	TOTAL Deprec. Prov. for Year (Enter Total of lines 3 thru 8)..				
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired......	0			
12	Cost of Removal......				
13	Salvage (Credit)......				
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru				
15	Other Debit or Credit Items (Describe)				
16	Balance End of Year (Enter Total of				
17	lines 1, 9, 14, 15, and 16)......				

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

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)
18	Steam Production......				
19	Nuclear Production......				
20	Hydraulic Production - Conventional......				
21	Hydraulic Production - Pumped Storage......				
22	Other Production......				
23	Transmission......				
24	Distribution......				
25	General......				
26	TOTAL (Enter Total of lines 18 thru 25)				

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 year (on a supplemental page) showing general classes of material and supplies and the various accounts (operating expense, clearing accounts, plant, etc.) affected - debited or credited. Show separately debits or credits to stores expense-clearing, if applicable.

Line No.	Account (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)	Department or Departments Which Use Material (d)
1	Fuel Stock (Account 151)			
2	Fuel Stock Expenses Undistributed (Account 152)			
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	**INFORMATION NOT AVAILABLE BY STATE ON A SITUS BASIS.**		
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)			
9	Distribution Plant (Estimated)			
10	Assigned to - Other			
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	0		
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)			
15	Stores Expense Undistributed (Account 163)			
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)			

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (Classified)........	$ 247,396,160	$ 247,396,160				
4	Property Under Capital Leases........						
5	Plant Purchased or Sold........						
6	Completed Construction not Classified........						
7	Experimental Plant Unclassified........						
8	TOTAL (Enter Total of lines 3 thru 7)........	247,396,160	247,396,160				
9	Leased to Others........						
10	Held for Future Use........	$ 302,263	302,263				
11	Construction Work in Progress........						
12	Acquisition Adjustments........						
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)........	247,698,423	247,698,423				
14	Accum. Prov. for Depr., Amort., & Depl........	$ 96,003,535	96,003,535				
15	Net Utility Plant (Enter Total of line 13 less 14)........	$ 151,694,888	$ 151,694,888				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service						
18	Depreciation........	$ 94,952,768	$ 94,952,768				
19	Rights……………………..		0				
20	Amort. of Underground Storage Land and Land Rights........						
21	Amort. of Other Utility Plant........	$ 1,050,767	1,050,767				
22	TOTAL In Service (Enter total of lines 18 thru 21)........	96,003,535	96,003,535				
23	Leased to Others						
24	Depreciation........						
25	Amortization and Depletion........						
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)						
27	Held for Future Use						
28	Depreciation........						
29	Amortization........						
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)						
31	Abandonment of Leases (Natural Gas)........						
32	Amort. of Plant Acquisition Adj........						
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22,26,30,31,and 32).....	$ 96,003,535	$ 96,003,535				

ELECTRIC PLANT IN SERVICE	ELECTRIC PLANT IN SERVICE (Continued)
(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.) 1. Report below the original cost of electric plant in service according to prescribed accounts. 2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.	3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts. 4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. INTANGIBLE PLANT								1
2	(301) Organization..	$ 239					$ 246	(301)	2
3	(302) Franchises and Consents..	1,222,664					1,296,982	(302)	3
4	(303) Miscellaneous Intangible Plant...	1,192,103					979,957	(303)	4
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)...........	$ 2,415,005					$ 2,277,185		5
6	2. PRODUCTION PLANT								6
7	A. Steam Production Plant								7
8	(310) Land and Land Rights...							(310)	8
9	(311) Structures and Improvements...							(311)	9
10	(312) Boiler Plant Equipment………………………………………….							(312)	10
11	(313) Engines and Engine Driven Generators.............................							(313)	11
12	(314) Turbogenerator Units..							(314)	12
13	(315) Accessory Electric Equipment..							(315)	13
14	(316) Misc. Power Plant Equipment...							(316)	14
15	(317) Asset Retirement Costs for Steam Production Equipment..	0						(317)	15
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)..	$ 44,732,000					$ 50,388,480		16
17	B. Nuclear Production Plant								17
18	(320) Land and Land Rights...							(320)	18
19	(321) Structures and Improvements...							(321)	19
20	(322) Reactor Plant Equipment..							(322)	20
21	(323) Turbogenerator Units..							(323)	21
22	(324) Accessory Electric Equipment..							(324)	22
23	(325) Misc. Power Plant Equipment…………………………………							(325)	23
24	(326) Asset Retirement Costs for Nuclear Production..................							(326)	
25	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 24								25
26	C. Hydraulic Production Plant								26
27	(330) Land and Land Rights...							(330)	27
28	(331) Structures and Improvements...							(331)	28
29	(332) Reservoirs, Dams, and Waterways.....................................							(332)	29
30	(333) Water Wheels, Turbines, and Generators..........................							(333)	30

ELECTRIC PLANT IN SERVICE	ELECTRIC PLANT IN SERVICE (Continued)
(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.) 1. Report below the original cost of electric plant in service according to prescribed accounts. 2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.	3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts. 4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
31	(334) Accessory Electric Equipment..							(334)	31
32	(335) Misc. Power Plant Equipment..							(335)	32
33	(336) Roads, Railroads, and Bridges...							(336)	33
34	(337) Asset Retirement Costs for Hydraulic Production...............							(326)	34
35	TOTAL Hydraulic Production Plant (Enter Total of lines 26 thru 3	$ 32,087,497					$ 35,395,917		35
36	D. Other Production Plant								36
37	(340) Land and Land Rights...							(340)	37
38	(341) Structures and Improvements..							(341)	38
39	(342) Fuel Holders, Products and Accessories............................							(342)	39
40	(343) Prime Movers...							(343)	40
41	(344) Generators..							(344)	41
42	(345) Accessory Electric Equipment..							(345)	42
43	(346) Misc. Power Plant Equipment..							(346)	43
44	(347) Asset Retirement Costs for Other Production.....................							(347)	44
45	TOTAL Other Production Plant (Enter Total of lines 36 thru 44)	$ 22,122,237					$ 23,756,593		45
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 4	98,941,734					109,540,989		46
47	3. TRANSMISSION PLANT								47
48	(350) Land and Land Rights..	1,494,619					1,606,215	(350)	48
49	(352) Structures and Improvements...	3,196,200					3,435,614	(352)	49
50	(353) Station Equipment...	16,778,095					17,793,478	(353)	50
51	(354) Towers and Fixtures..	7,585,368					8,555,197	(354)	51
52	(355) Poles and Fixtures..	6,539,437					7,597,332	(355)	52
53	(356) Overhead Conductors and Devices.....................................	8,730,233					9,491,104	(356)	53
54	(357) Underground Conduit...							(357)	54
55	(358) Underground Conductors and Devices................................							(358)	55
56	(359) Roads and Trails...	16,034					16,854	(359)	56
57	(359.1) Asset Retirement Costs for Transmission Plant..............							(359.1)	57
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57).....	$ 44,339,986					$ 48,495,794		58
59	4. DISTRIBUTION PLANT								59
60	(360) Land and Land Rights..	124,389					133,293	(360)	60
61	(361) Structures and Improvements...	1,530,958					1,974,292	(361)	61
62	(362) Station Equipment...	9,789,607					7,883,642	(362)	62
63	(363) Storage Battery Equipment...	0					0	(363)	63
64	(364) Poles, Towers, and Fixtures..	18,842,485					19,545,721	(364)	64
65	(365) Overhead Conductors and Devices.....................................	8,804,153					8,875,388	(365)	65
66	(366) Underground Conduit...	650,604					683,071	(366)	66
67	(367) Underground Conductors and Devices................................	3,122,355					3,392,229	(367)	67
68	(368) Line Transformers...	19,480,444					21,661,410	(368)	68
69	(369) Services..	2,871,692					2,874,370	(369)	69
70	(370) Meters...	2,913,941					3,038,596	(370)	70
71	(371) Installations on Customer Premises....................................	224,697					228,022	(371)	71

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.

ELECTRIC PLANT IN SERVICE (Continued)

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
72	(372) Leased Property on Customer Premises................................							(372)	72
73	(373) Street Lighting and Signal Systems..	209,733					208,837	(373)	73
74	(374) Asset Retirement Costs for Distribution Plant........................							(374)	74
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)...........	$ 68,565,058					$ 70,498,871		75
76	5. GENERAL PLANT								76
77	(389) Land and Land Rights..	693,603					741,412	(389)	77
78	(390) Structures and Improvements..	4,640,784					5,112,949	(390)	78
79	(391) Office Furniture and Equipment...	1,953,469					2,118,653	(391)	79
80	(392) Transportation Equipment..	3,174,564					3,514,970	(392)	80
81	(393) Stores Equipment...	94,360					113,094	(393)	81
82	(394) Tools, Shop, and Garage Equipment.....................................	335,600					374,081	(394)	82
83	(395) Laboratory Equipment..	531,493					562,119	(395)	83
84	(396) Power Operated Equipment...	630,991					651,156	(396)	84
85	(397) Communication Equipment..	2,318,420					2,442,885	(397)	85
86	(398) Miscellaneous Equipment..	249,672					283,656	(398)	86
87	SUBTOTAL (Enter Total of lines 77 thru 86)...............................	14,622,957					15,914,976		87
88	(399) Other Tangible Property *...							(399)	88
89	(399.1) Asset Retirement Costs for General Plant.........................							(399.1)	89
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89).........	14,622,957					15,914,976		90
91	TOTAL (Accounts 101 and 106)...	228,884,742					246,727,815		91
92	(102) Electric Plant Purchased **..								92
93	(Less) (102) Electric Plant Sold **..								93
94	Asset Retirement Obligations (ARO)..	579,057					668,345		94
95	TOTAL Electric Plant in Service...	$ 229,463,798					$ 247,396,160		95

* State the nature and use of plant included in this account and if substantial in amount submit a supplementary schedule showing subaccount classification of such plant conforming to the requirements of this schedule.

** For each amount comprising the reported balance and charges 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.

NOTE

Completed Construction Not Classified, Account 106, shall be classified in this schedule according to prescribed accounts, on an estimated basis if necessary, and the entries included in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (c). 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, a tentative distribution of such retirements, on an estimated basis with appropriate contra entry to the account for accumulated depreciation provision, shall be included in column (d). Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach an insert page 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.

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

1. Report below the information called for concerning accumulated provision for depreciation of electric utility plant.
2. Explain any important adjustments during year.
3. Explain any difference between the amount for book cost of plant retired, line.., column (c), and that reported in the schedule for electric plant in service, pages 401-403, column (d) exclusive of retirements of nondepreciable property.
4. The provisions of account 108 in the Uniform System of Accounts contemplate 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, preliminary closing entries should be made to tentatively functionalize the book cost of the plant retired. In addition, all cost included in retirement work in progress at year end should be included in the appropriate functional classifications.
5. Show separately interest credits under a sinking fund or similar method of depreciation accounting.
6. In section B show the amounts applicable to prescribed functional classifications.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	$	$		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	5,937,323	5,937,323		
4	(413) Exp. of Elec. Plt. Leas. to Others				
5	Transportation Expenses-Clearing				
6	Other Clearing Accounts				
7	Other Accounts (Specify)				
8					
9	TOTAL Deprec. Prov. for Year (Enter Total of lines 3 thru 8)	5,937,323	5,937,323		
10	Net Charges for Plant Retired				
11	Book Cost of Plant Retired	0			
12	Cost of Removal				
13	Salvage (Credit)				
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)				
15	Other Debit or Credit Items (Describe)				
16	Balance End of Year (Enter Total of				
17	lines 1, 9, 14, 15, and 16)	$ 5,937,323	$ 5,937,323		

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

Line No.	Item (a)	Total (c+d+e) (b)	Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
18	Steam Production	$ 23,638,840	$ 23,638,840		
19	Nuclear Production				
20	Hydraulic Production - Conventional	17,865,929	17,865,929		
21	Hydraulic Production - Pumped Storage				
22	Other Production	4,557,335	4,557,335		
23	Transmission	15,168,253	15,168,253		
24	Distribution	28,410,730	28,410,730		
25	General	4,758,852	4,758,852		
26	FAS 143 Adj &/or Disallowed Cost	552,828	552,828		
27	TOTAL (Enter Total of lines 18 thru 26)	$ 94,952,768	$ 94,952,768		

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 year (on a supplemental page) showing general classes of material and supplies and the various accounts (operating expense, clearing accounts, plant, etc.) affected - debited or credited. Show separately debits or credits to stores expense-clearing, if applicable.

Line No.	Account (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)	Department or Departments Which Use Material (d)
1	Fuel Stock (Account 151)...	$ 2,821,708	$ 2,505,647	
2	Fuel Stock Expenses Undistributed (Account 152)..................			
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)...	714,250	753,259	
8	Transmission Plant (Estimated)..	460,708	577,730	
9	Distribution Plant (Estimated)...	953,899	914,578	
10	Assigned to - Other..	79,973	104,580	
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)..........	2,208,831	2,350,148	
12	Merchandise (Account 155)...			
13	Other Materials and Supplies (Account 156)............................	0		
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)..			
15	Stores Expense Undistributed (Account 163)............................	187,342	146,928	
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)............	$ 5,217,881	$ 5,002,722	

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, and interchanged during the year.

Line No.	Item (a)	Megawatt Hours (b)	Line No.	Item (a)	Megawatt Hours (b)
1	SOURCES OF ENERGY		20	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		21	Sales to Ultimate Consumers (Including Interdepartmental Sales)	
3	Steam.......... Steam.................................				
4	Nuclear...		22	Sales for Resale	
5	Hydro-Conventional....................................		23	Energy Furnished Without Charge	
6	Hydro-Pumped Storage.............................	**INFORMATION**	24	Energy Used by the Company (Excluding Station Use):	**INFORMATION**
7	Other..				
8	Less Energy for Pumping.........................	**NOT**	25	Electric Department Only	**NOT**
9	Net Generation (Enter Total of lines 3 thru 8)....................................	**AVAILABLE**	26	Energy Losses:	**AVAILABLE**
10	Purchases..		27	Transmission and Conversion Losses	
11	Interchanges:		28	Distribution Losses	
12	In (gross)..		29	Unaccounted for Losses	
13	Out (gross)...		30	TOTAL Energy Losses	
14	Net Interchanges (Lines 12 & 13).............		31	Energy Losses as Percent of Total on Line 19	
15	Transmission for/by Others (Wheeling)				
16	Received (MWH)		32	TOTAL (Enter Total of lines 21, 22, 23, 25, and 30)	
17	Delivered (MWh)				
18	Net Transmission (lines 16 & 17).............				
19	TOTAL (Enter Total of lines 9, 10, 14, and 18).........................				

MONTHLY 0 0 0 0 0 0 0 0

1. Report below the information called for pertaining to simultaneous peaks established monthly (in megawatts) and monthly output (in megawatt-hours) for the combined sources of electric energy of respondent.
2. Report in column (b) the respondent's maximum MW load as measured by the sum of its coincidental net generation and purchases plus or minus net interchange, minus temporary deliveries (not interchange) Show monthly peak including such emergency deliveries of emergency power to another system. in a footnote and briefly explain the nature of the emergency. There may be cases of commingling of purchases and exchanges and "wheeling," also of direct deliveries by the supplier to customers of the reporting utility wherein segregation of MW demand for determination of peaks as specified by this report may be unavailable. In these cases, report peaks which include these intermingled transactions. Furnish an explanatory note which indicates, among other things, the relative significance of the deviation from basis otherwise applicable. If the individual MW amounts of such totals are needed for billing under separate rate schedules and are estimated, give the amount and basis of estimate.
3. State type of monthly peak reading (instantaneous 15, 30, or 60 minutes integrated).
4. Monthly output is the sum of respondent's net generation for load and purchases plus or minus net interchange and plus or minus net transmission or wheeling. Total for the year must agree with line 19 above.
5. If the respondent has two or more power systems not physically connected, furnish the information called for below for each system.

NAME OF SYSTEM: **OREGON RETAIL ONLY**

Line No.	Month (a)	MONTHLY PEAK Megawatts (b)	Day of Week (c)	Day of Month (d)	Hour (e)	Type of Reading (f)	Monthly Output (MWh) (See Instr. 4) (g)
33	January	93.28	Saturday	2	10 A.M	60 Min. Int	56,217
34	February	90.63	Tuesday	2	8 A.M.	" " "	50,960
35	March	89.16	Friday	18	8 A.M.	" " "	53,238
36	April	80.53	Thursday	21	6 P.M.	" " "	51,220
37	May	86.18	Tuesday	31	7 P.M.	" " "	58,320
38	June	122.13	Tuesday	28	7 P.M.	" " "	68,822
39	July	130.85	Saturday	30	6 P.M.	" " "	70,638
40	August	127.32	Tuesday	2	7 P.M.	" " "	74,655
41	September	102.97	Thursday	1	6 P.M.	" " "	52,364
42	October	81.27	Monday	17	8 P.M.	" " "	54,368
43	November	91.24	Wednesday	30	7 P.M.	" " "	57,062
44	December	120.48	Monday	19	9 A.M.	" " "	68,061
45	TOTAL	1,216.04					715,925

MISCELLANEOUS GENERAL EXPENSES (Account 930.2)

Report below the information called for concerning items included in miscellaneous general expenses.

Line No.	Items (a)	Total (b)	Amount Applicable to Oregon (c)	Amount Applicable to Other States (d)
1	Industry association dues....	$ 516,427	$ 24,710	$ 491,717
2	Nuclear power research expenses (elec.)....			
3	Other experimental and general research expenses....			
4	Publishing and distributing information and reports to stockholders;			
5	trustee, registrar, and transfer agent fees and expenses, and other			
6	expenses of servicing outstanding securities of the respondent....	1,652,922	79,089	1,573,833
7	Other expenses (items of $100 or more must be listed separately show-			
8	ing the (1) purpose, (2) recipient, and (3) amount of such items.			
9	Amounts of less than $100 may be grouped by classes if the number	98,070	4,692	93,378
10	of items so grouped is shown)			
11				
12				
13	Directors' fees and expenses (see detail on page 39)....	816,987	39,091	777,896
14				
15	Memberships and contributions (see detail on page 39)....	439,115	21,011	418,104
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39	**TOTAL**	$ 3,523,521	$ 168,594	$ 3,354,927

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (Continued)

Report below the information called for concerning items included in miscellaneous general expenses.

Line No.	Items (a)	Total (b)	Amount Applicable to Oregon (c)	Amount Applicable to Other States (d)
1				
2	Directors' Fees and Expenses:			
3	Christine King-Fees and expenses	$ 91,305	4,369	86,936
4	Richard Navarro - Fees and expenses	$ 69,959	3,347	66,612
5	Dennis Johnson - Fees and expenses	64,025	3,063	60,962
6	J LaMont Keen - Fees and expenses	77,647	3,715	73,932
7	Judith Johansen-Fees and expenses	91,112	4,360	86,752
8	Richard Dahl - Fees	76,166	3,644	72,522
9	Robert A Tinstman Fees and expenses	177,685	8,502	169,183
	Ronald Jibson - Fees and expenses	71,144	3,404	67,740
10	Thomas Carlile - Fees and expenses	75,845	3,629	72,216
11	Director travel and lodging	22,099	1,057	21,042
12	SUBTOTAL	816,987	39,091	777,897
13				
14	Other Expenses >$5,000:			
15	Bank of New York	$ 12,925	618	12,307
16	Inspirus, LLC	54,848	2,624	52,224
17	Investis, Inc	12,637	605	12,032
18	Payroll Related Expenses	17,660	845	16,815
19	Miscellaneious <$5,000	-	0	0
20	SUBTOTAL	98,070	4,692	93,378
21	Miscellaneous General Management Expenses:			
22	American Stock Transfer & Trust	69,353	3,318	66,035
23	Bloomberg Finance LP	11,299	541	10,758
24	Broadridge Financial Solutions	47,512	2,273	45,239
25	Deutche Bank	30,000	1,435	28,565
26	E Source	41,499	1,986	39,513
27	Moody's Analytics	33,708	1,613	32,095
28	NASDAQ Corp Solutions	91,616	4,384	87,232
29	New York Stock Exchange	51,917	2,484	49,433
30	Payroll Related Expenses	249,271	11,927	237,344
31	PR Newswire	15,662	749	14,913
32	Rivel Research Group	15,840	758	15,082
33	Stock Based Compensation	890,845	42,625	848,220
34	Wells Fargo Shareowner Services	104,400	4,995	99,405
35	SUBTOTAL	1,652,922	79,089	1,573,834
36				
37	Memberships and Contributions:			
38	Associated Taxpayers of Idaho - Membership	26,000	1,244	24,756
39	Business Plus	5,000	239	4,761
40	Chambers of Commerce	85,875	4,109	81,766
41	Idaho Association of Commerce & Industry	15,000	718	14,282
42	Idaho Technology Council	12,350	591	11,759
43	National Association of Directors	7,125	341	6,784
44	Nathional Hydropower Assocaiation	35,860	1,716	34,144
45	North American Energy sStandard	7,000	335	6,665
46	Northwest Power Pool	158,932	7,605	151,327
47	Pacific NW Utilities	42,747	2,045	40,702
48	SNL Financial Unlimited Subscription	25,931	1,241	24,690
49	Western Energy Coordination Council	(21,979)	(1,052)	(20,927)
50	Western Energy Institute	30,988	1,483	29,505
51	Misc Memberships under $2,000	8,286	396	7,890
52	SUBTOTAL	439,115	21,011	418,104
53				
54				
55				
56				
57				
58				
59				
60	**TOTAL**	$ 3,007,094	$ 139,191	$ 2,867,903

OFFICERS

1. Report below the name, title and salary for the year for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance) and any other person who performs similar policy making functions.

2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and date change in incumbency was made.

3. Utilities which are required to file similar data with the Securities and Exchange Commission, may substitute a copy of item 4 of Regulation S-K identified as

Line No.	Title (a)	Name of Officer (b)	Salary for year Total	Salary for year Oregon
1				
2	President & Chief Executive Officer….....................................	Darrel T Anderson	$ 750,000	$ 35,886
3				
4	Executive Vice President...	Dan Minor (1)	245,923	11,767
5				
6	Sr Vice President...	Rex Blackburn (2)	360,000	17,225
7				
8	Senior Vice President, CFO and Treasurer …..........................	Steven R. Keen	380,000	18,182
9				
10	Senior Vice President, Operations...	Lisa Grow	360,000	17,225
11				
12	Vice President, Public Affairs...	Jeffrey Malmen	285,000	13,637
13				
14	Vice President, Customer Operations......................................	Vern Porter	285,000	13,637
15				
16	Senior Vice President, Human Resources, Admin Services……	Lonnie Krawl	275,000	13,158
17				
18	Vice President & Chief Risk Officer	Lori Smith (3)	70,846	3,390
19				
20	Vice President, Corporate Controller & CAO............................	Ken Petersen	245,000	11,723
21				
22	Vice President, Regulatory Affairs...	Gregory Said (4)	81,904	3,919
23				
24	Corporate Secretary..	Patrick Harrington	195,000	9,330
25				
26	Vice President of Power Supply...	Tessia Park	220,000	10,527
27				
28	Vice President & General Counsel...	Brian Buckham	230,000	11,005
29				
30	Vice President Information Technology & CIO.........................	Jeff Glenn	210,000	10,048
31				
32	Vice President of Rgulatory Affairs..	Tim Tatum	170,000	8,134
33				
34				
35	(1) Retirement effective 6/30/2016. Base shows YTD wages			
36	(2) Retirement effective 12/31/2016. Base shows YTD wages			
37	(3) Retirement effective 3/31/2016 Base shows YTD wages			
38	(4) Retirement effective 4/30/2016 Base shows YTD wages			
39				
40				

POLITICAL ADVERTISING

INSTRUCTIONS: List all payments for advertising, the purpose of which is to aid or defeat any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. Give the specific purpose of such advertising, when and where placed, and the account or accounts charged. Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
None		

POLITICAL CONTRIBUTIONS

INSTRUCTIONS: List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. The purpose of all contributions or payments should be clearly explained.
Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
2016 2C GOP	426.400	$ 1,000
2016 NORTH IDAHO LEGISLATIVE T	"	2,000
ABBEY LEE FOR STATE SENATE	"	1,000
ADA COUNTY LINCOLN DAY ASSOCIA	"	2,000
ADVANTAGE INC	"	2,577
ALAN OLSEN FOR STATE SENATE	"	500
BRAD WITT FOR STATE REPRESENTA	"	500
BRANDON HIXON FOR STATE REPRES	"	250
BRIAN BOQUIST LEADERSHIP FUND	"	500
CARL CRABTREE FOR STATE SENATE	"	500
CAROLINE TROY FOR STATE REPRES	"	1,250
CHERIE BUCKNER-WEBB FOR STATE	"	1,000
CHRISTY PERRY FOR STATE REPRES	"	750
CHUCK WINDER FOR STATE SENATE	"	1,000
CITIZENS FOR HJR 5	"	5,000
CLARK KAUFFMAN FOR STATE REPRE	"	200
COMMITTEE TO ELECT MIKE MCLANE	"	1,000
COMMITTEE TO ELECT SAL ESQUIVE	"	250
COMMITTEE TO RE-ELECT GREG SMI	"	500
COUNCIL OF STATE GOVERNMENTS-W	"	5,000
CURT MCKENZIE FOR SUPREME COUR	"	3,500
DAVID SMITH FOR STATE REPRESEN	"	500
DEBORAH BOONE FOR STATE	"	250
DEFEAT THE TAX ON OREGON SALES	"	10,000
DELL RAYBOULD FOR STATE REPRES	"	500
DEMORDAUNT, GAYANN	"	500
ELLEN ROSENBLUM FOR ATTORNEY G	"	2,500
ERIC REDMAN FOR STATE REPRESEN	"	500
FRED MARTIN FOR STATE SENATE	"	500
FRIENDS OF BILL HANSELL	"	500
FRIENDS OF CHRIS EDWARDS	"	1,000
FRIENDS OF GINNY BURDICK	"	2,000
FRIENDS OF JENNIFER WILLIAMSON	"	1,000
FRIENDS OF MARK HASS	"	2,000
FRIENDS OF MARK JOHNSON	"	1,000
FRIENDS OF PATTI MILNE	"	1,000
FRIENDS OF TINA KOTEK	"	1,000
FRIENDS OF TOBIAS READ	"	1,000

POLITICAL CONTRIBUTIONS

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Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
GARY COLLINS FOR STATE	426.400	500
GAYANN DEMORDAUNT FOR STATE RE	"	250
GRANT BURGOYNE FOR STATE SENAT	"	500
GREG BARRETO FOR HD 58	"	500
GREG CHANEY FOR STATE REPRESEN	"	250
HEATHER SCOTT FOR STATE REPRES	"	250
HY KLOC FOR STATE REPRESENTATI	"	250
IDAHO ASSOCIATION OF HIGHWAY D	"	10,000
IDAHO DEMOCRATIC LEGISLATIVE C	"	500
IDAHO GOVERNOR'S CUP SCHOLARSH	"	5,000
IDAHO MINING ASSOCIATION	"	90
IDAHO POLICY INSTITUTE	"	2,000
IDAHO PROSPERITY FUND	"	23,500
IDAHO REPUBLICAN PARTY	"	1,000
IDAHO STATE SOCIETY	"	12,869
IDAHO WATER USERS ASSOCIA	"	500
JANET TRUJILLO FOR STATE REPRE	"	500
JANIE WARD-ENGELKING FOR STATE	"	250
JEFF AGENBROAD FOR STATE SENAT	"	500
JEFF REARDON FOR OREGON	"	250
JEFF THOMPSON FOR STATE REPRES	"	500
JIM PATRICK FOR STATE SENATE	"	500
JIM RICE FOR STATE SENATE	"	500
JOHN GANNON FOR STATE REPRESEN	"	250
JOHN MCCROSTIE FOR STATE REPRE	"	750
JOHN RUSCHE FOR STATE REPRESEN	"	750
JUDY BOYLE FOR STATE REPRESENT	"	750
JULIE VAN ORDEN FOR STATE REPR	"	200
KELLEY PACKER FOR STATE REPRES	"	700
KELLY ANTHON FOR STATE SENATE	"	500
KEN HELM FOR HD 34	"	1,000
LANCE CLOW FOR STATE REPRESENT	"	250
LEADERSHIP FUND, THE	"	1,000
LEE HEIDER FOR STATE SENATE	"	500
LORI DEN HARTOG FOR STATE SENA	"	750
LUKE MALEK FOR STATE REPRESENT	"	1,500
LYNN LUKER FOR STATE REPRESENT	"	250
MARK HARRIS FOR STATE SENATE	"	500

POLITICAL CONTRIBUTIONS

INSTRUCTIONS: List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. The purpose of all contributions or payments should be clearly explained.
Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
MARK NYE FOR STATE SENATE	426.400	500
MARV HAGEDORN FOR STATE SENATE	"	500
MARYANNE JORDAN FOR STATE SENA	"	250
MAT ERPELDING FOR STATE REPRES	"	650
MAXINE BELL FOR STATE REPRESEN	"	500
MEGAN BLANKSMA FOR STATE REPRE	"	500
MERRILL BEYELER FOR STATE REPR	"	500
MICHELLE STENNETT FOR STATE SE	"	750
MIKE MOYLE FOR STATE REPRESENT	"	250
NATL CONFERENCE OF ST LEGISLAT	"	1,000
NEIL ANDERSON FOR STATE REPRES	"	700
NEW HORIZONS PAC	"	5,000
PACIFIC NORTHWEST ECONOMIC REG	"	5,000
PAT MCDONALD FOR STATE REPRESE	"	750
PATTI ANNE LODGE FOR	"	1,250
PAUL AMADOR FOR STATE REPRESEN	"	500
PAUL HOLVEY FOR STATE REPRESEN	"	250
PAUL ROMRELL FOR STATE REPRESE	"	700
PAUL SHEPHERD FOR STATE REPRES	"	500
PETER COURTNEY FOR STATE SENAT	"	1,000
PORTLAND GENERAL ELECTRIC	"	500
PRISCILLA GIDDINGS FOR STATE R	"	500
RANDY ARMSTRONG FOR STATE REPR	"	250
RICH WILLS FOR STATE REPRESENT	"	500
RICK YOUNGBLOOD FOR STATE REPR	"	250
ROBERT ANDERST FOR STATE REPRE	"	250
RYAN KERBY FOR STATE REPRESENT	"	250
SAGE DIXON FOR STATE REPRESENT	"	250
SCOTT BEDKE FOR STATE REPRESEN	"	1,250
SCOTT SYME FOR STATE REPRESENT	"	750
SENATE REPUBLICAN CAUCUS	"	500
SHAWN KEOUGH FOR STATE SENATE	"	1,000
SOUTH DAKOTA ELECTRIC UTILITY	"	700
STEPHEN HARTGEN FOR STATE REPR	"	750
STEVE BAIR FOR STATE SENATE	"	500
STEVE MILLER FOR STATE REPRESE	"	250
STEVE VICK FOR STATE SENATOR	"	500
STEVEN HARRIS FOR STATE REPRES	"	250

POLITICAL CONTRIBUTIONS

INSTRUCTIONS: List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. The purpose of all contributions or payments should be clearly explained.
Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
TERRY GESTRIN FOR STATE REPRES	426.400	500
THE KATE BROWN COMMITTEE	"	5,000
THOMAS DAYLEY FOR STATE REPRES	"	250
TODD LAKEY FOR STATE SENATE	"	1,000
VAN BURTENSHAW FOR STATE REPRE- (Refund)	"	(500)
VITO BARBIERI FOR STATE REPRES	"	500
WENDY HORMAN FOR STATE REPRESE	"	700
Total Political Contributions		**$ 164,337**

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EXPENDITURES TO ANY PERSON OR ORGANIZATION HAVING AN AFFILIATED INTEREST FOR SERVICES, ETC.

INSTRUCTIONS: Report all expenditures to any person or organization having an affiliated interest for service, advice, auditing, associating, sponsoring, engineering, managing, operating, financial, legal or other services. See Oregon Revised Statute 757.015 for definition of “affiliated interest.” Give reference if such expenditures have in the past been approved by the Commission. Describe the services received and the account or accounts charged. Report whole dollars only.

Description	Account Charged	Total Amount	Amount Assigned to Oregon
Idaho Power does not have any expenditures to its affiliated companies			
		0	

INSTRUCTIONS: List all donations made by the utility during the year and the accounts charged (Items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name city and state of each organization to whom a donation has been made. Group donations under headings such as:

1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group

Description	Account Number	Total Amount	Amount Assigned to Oregon
IDACORP	426101	58,488	None
IDACORP EMPLOYEES	"	161,062	"
TOTAL MATCHING EMPLOYEE COMMUNITY SERVICE FUND	**426101**	**219,550**	
AMERICAN HEART ASSOCIATION- AZ	426102	7,500	None
AMERICAN RED CROSS OF GREATER	"	1,500	"
BOISE RESCUE MISSION	"	2,500	"
CANYON COUNTY FESTIVAL	"	2,228	"
CHAMBER OF COMMERCE	"	1,430	"
CHILDREN'S HOME SOCIETY OF ID	"	1,250	"
DESIGNS BY DE	"	1,930	"
FESTIVAL OF TREES	"	1,125	"
GIRL SCOUTS OF SILVER SAGE COU	"	5,000	"
IDAHO RONALD MCDONALD HOUSE	"	2,500	"
METRO MEALS ON WHEELS	"	1,000	"
ST ALPHONSUS FESTIVAL OF TREES	"	5,000	"
ST LUKES HEALTH FOUNDATION	"	7,500	0
WESTERN IDAHO TRAINING CO, INC	"	1,000	"
Misc Health & Human Services - 41 Organizations <$1,000	"	13,033	"
TOTAL HEALTH & HUMAN SERVICES	**426102**	**54,496**	
BAKER SANITARY	**426103**	1,091	None
BITE SIZED OWYHEE	"	2,627	"
ACCESS TO JUSTICE IDAHO	"	2,500	"
BAKER COUNTY FAIR - HALFWAY	"	1,790	"
BOYS & GIRLS CLUB OF ADA CO	"	2,500	"
CHAMBER OF COMMERCE (5)	"	14,628	"
CHAMBERS,MELINDA S	"	4,622	"
COMMUNITY FORESTRY TRUST	"	6,815	"
EV CHARGING STATION	"	4,005	"
FRIENDS OF ZOO BOISE	"	3,700	"
FUNDSY	"	5,000	"
GARDEN CITY LIBRARY FOUNDATION	"	1,500	"
GOODING VOLUNTEER GROUP	"	1,500	"
HORSESHOE BEND CITY	"	1,300	"
IDAHO BOTANICAL GARDEN	"	5,000	"

INSTRUCTIONS: List all donations made by the utility during the year and the accounts charged (Items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name city and state of each organization to whom a donation has been made. Group donations under headings such as:

1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group

Description	Account Number	Total Amount	Amount Assigned to Oregon
IDAHO COMMISSION ON HISPA	"	2,000	None
IDAHO COMMUNITY FOUNDATION	"	2,500	"
IDAHO FOODBANK	"	2,750	"
IDAHO HUMANE SOCIETY	"	13,000	"
IDAHO NONPROFIT CENTER	"	1,200	"
IDAHO PATRIOT THUNDER RIDE	"	1,000	"
IDAHO POTATO MUSEUM	"	1,500	"
IDAHO SALMON AND STEELHEAD DAY	"	2,500	"
IDAHO STATE UNIVERSITY	"	2,900	"
IDAHO WOMEN LAWYERS	"	1,500	"
KETCHUM COMMUNITY DEVELOPMENT	"	2,500	"
LAND TRUST OF THE TREASURE VAL	"	2,000	"
LUPO,MARK J	"	5,877	"
MCPAWS REGIONAL ANIMAL SHELTER	"	2,000	"
MECKELSON,SUSAN K	"	1,125	"
NEIGHBORWORKS	"	4,000	"
PEREGRINE FUND INC, THE	"	5,000	"
POCATELLO / CHUBBUCK EDUCATION	"	1,500	"
PORTNEUF GREENWAY FOUNDATION	"	1,000	"
PORTNEUF VALLEY PAINTFEST	"	1,000	"
ROTARY CLUB	"	1,142	"
ROTARY DISTRICT 5400	"	1,250	"
ROWEN,CASEY L	"	1,363	"
SMART WOMEN, SMART MONEY INC	"	5,000	"
STUTZMAN,SHARON E	"	2,012	"
TRAVIS,GREGORY M	"	3,124	"
TREASURE VALLEY NAACP	"	1,500	"
TWIN FALLS COUNTY FAIR FOUNDAT	"	1,000	"
WASSMUTH CENTER FOR HUMAN RIGH	"	1,000	"
WOMEN'S & CHILDREN'S ALLIANCE	"	5,000	"
WREATHS ACROSS AMERICA	"	1,000	"
WYAKIN WARRIOR FOUNDATION	"	2,500	"
Misc Civic and Community Serivices - 146 Organizations < $1,000	"	43,210	"
TOTAL CIVIC & COMMUNITY	**426103**	**184,531**	

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1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group

Description	Account Number	Total Amount	Amount Assigned to Oregon
BASQUE MUSEUM AND CULTURAL CEN	426104	2,500	None
BOISE ART MUSEUM	"	3,000	"
BOISE CONTEMPORARY THEATER INC	"	2,000	"
BOISE MUSIC WEEK	"	1,000	"
BOISE PHILHARMONIC ASSOCIATION	"	2,500	"
BRANDON WOOLF FOR STATE CONTRO	"	1,000	"
BUSINESS INSTITUTE FOR PAC	"	2,500	"
FOUR RIVERS CULTURAL CENTER	"	1,600	"
IDAHO MINING ASSOCIATION	"	6,500	"
IDAHO SHAKESPEARE FESTIVAL	"	3,500	"
LOG CABIN LITERARY CENTER	"	2,000	"
MERIDIAN SYMPHONY ORCHESTRA	"	1,000	"
WESTERN GOVERNORS' ASSOCIATION	"	5,000	"
Misc Culture and Arts - 19 Organizations <$1,000	"	7,125	"
TOTAL CULTURE & ARTS	**426104**	**41,225**	
IDAHO PUBLIC TELEVISION	426105	20,000	None
TOTAL PUBLIC TV & RADIO MATCH	**426105**	**20,000**	
Misc Volunteer Involvement Programs- 38 Organizations <$1,001	426106	5,300	None
TOTAL VOLUNTEER INVOLVEMENT PROGRAM	**426106**	**5,300**	
SALVATION ARMY	426107	43,270	None
TOTAL PROJECT SHARE	**426107**	**43,270**	
Misc Education Programs - 10 Organizations <$1,000	426108	2,482	None
TOTAL ENVIROMENT & CONSERVATION	**426108**	**2,482**	
CITY OF BOISE HERITAGE FUND	426109	20,000	None
IDAHO BUSINESS FOR EDUCATION	"	5,000	"
IDAHO COMMUNITY FOUNDATION	"	2,500	"
IDAHO GOVERNOR'S CUP SCHOLARSH	"	17,500	"
IDAHO YOUTH RANCH	"	50,000	"
SALVATION ARMY	"	28,334	"
TEACH FOR AMERICA	"	10,000	"
TREASURE VALLEY FAMILY YMCA	"	50,000	"
WOMEN'S & CHILDREN'S ALLIANCE	"	25,000	"
TOTAL NON-PROGRAM	**426109**	**208,334**	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
BOISE PUBLIC SCHOOLS	426110	3,000	None
BOISE STATE UNIVERSITY COLLEGE	"	2,500	"
COLLEGE OF IDAHO BOX 48	"	4,750	"
COLLEGE OF SOUTHERN IDAHO	"	3,220	"
COLLEGE OF WESTERN IDAHO	"	3,500	"
COLLEGE OF WESTERN IDAHO FOUND	"	1,200	"
DISCOVERY CENTER OF IDAHO	"	7,500	"
IDAHO STATE UNIVERSITY	"	3,500	"
IDAHO STEM ACTION CENTER	"	1,500	"
JUNIOR ACHIEVEMENT OF IDAHO	"	2,900	"
LEARNING LAB	"	1,000	"
LUPO,MARK J	"	1,163	"
NORTHWEST NAZARENE UNIVERSITY	"	3,500	"
SOCIETY OF WOMEN ENGINEERS	"	2,500	"
TREASURE VALLEY COMMUNITY COLL	"	3,500	"
Misc Education Programs - 64 Organizations <$1,000	"	13,283	"
TOTAL EDUCATION	**426110**	**58,516**	
BOISE STATE UNIVERSITY	426111	8,000	None
BRIGHAM YOUNG UNIVERSITY CES A	"	4,000	"
COLLEGE OF SOUTHERN IDAHO	"	5,000	"
EASTERN OREON UNIVERSITY	"	2,000	"
HARVARD COLLEGE	"	2,000	"
IDAHO STATE UNIVERSITY	"	1,000	"
MAINE MARITIME ACADEMY	"	2,000	"
MONTANA STATE UNIVERISTY FOUND	"	2,000	"
NORTHWEST NAZARENE UNIVERSITY	"	2,000	"
OREGON HEALTH & SCIENCE UNIVER	"	2,000	"
SOUTHWESTERN OREGON COMMUNITY	"	4,000	"
UNIVERSITY OF IDAHO	"	14,000	"
UNIVERSITY OF MONTANA	"	2,000	"
UNIVERSITY OF OREGON	"	2,000	"
UNIVERSITY OF PORTLAND	"	2,000	"
UNIVERSITY OF SOUTHERN CALIFOR	"	2,000	"
UNIVERSITY OF UTAH	"	4,000	"

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List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group

Description	Account Number	Total Amount	Amount Assigned to Oregon
TOTAL SCHOLARSHIP PROGRAMS	**426111**	**60,000**	
BOISE STATE UNIVERSITY	426112	1,350	None
COLLEGE OF IDAHO	"	1,500	"
COLLEGE OF IDAHO BOX 48	"	1,500	"
IDAHO STATE UNIVERSITY	"	3,005	"
NORTHWEST NAZARENE UNIVERSITY	"	2,000	"
UNIVERSITY OF IDAHO FOUNDATION	"	11,060	"
Misc Non-Cash Contributions - 8 Organizations <$1,000	"	1,675	"
TOTAL HIGHER EDUCATION MATCH	**426112**	**22,090**	
BANNOCK DEVELOPMENT CORPO	426121	3,000	None
BOISE VALLEY ECONOMIC PARTNERS	"	3,000	"
CHAMBER OF COMMERCE	"	6,000	"
CITY OF CALDWELL	"	2,750	"
DESTINATION CALDWELL	"	3,000	"
DOWNTOWN BOISE ASSOCIATION	"	3,000	"
GREAT RIFT BUSINESS DEVELOPMEN	"	2,450	"
LEMHI COUNTY ECONOMIC DEVELOPM	"	2,213	"
MOUNTAIN HOME, CITY OF	"	3,000	"
NAMPA, CITY OF	"	2,750	"
SNAKE RIVER ECONOMIC DEVELOPME	"	3,050	"
SOUTHERN IDAHO ECONOMIC DEVELO	"	3,000	"
SOUTHERN IDAHO RURAL DEVELOPME	"	3,750	"
SUN VALLEY ECONOMIC DEVELOPMEN	"	3,278	"
VALLEY COUNTY ECONOMIC DEVELOP	"	1,500	"
Misc Match Higher Education - 5 Organizations <$1000	"	3,525	"
TOTAL MATCH HIGHER EDUCATION	**426121**	**49,266**	
Murphy Reynolds Wilson Fire Department	426130	7,500	None
Owyhee County	"	7,000	"
Misc Non-Cash Contributions - <$1,000	"	3,259	"
TOTAL NON-CASH CONTRIBUTIONS	**426130**	**17,759**	
TOTAL CONTRIBUTIONS ACCOUNT 426.1		**986,820**	None

DONATIONS OR PAYMENTS FOR SERVICES RENDERED BY PERSONS OTHER THAN EMPLOYEES
AND CHARGED TO OREGON OPERATING ACCOUNTS

1. Report for each service rendered (including materials furnished incidental to the service which are impracticable of separation) by recipient and in total the aggregate of all payments made during the year where the aggregate of all such payments to a recipient was $25,000 or more including fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payments for services or as donations (except rents for property, taxes, utility services, traffic settlements, amounts paid for general services and licenses, accurals paid to trustees of pension and other employee benefit funds, and amounts paid for construction or maintenance of plant to persons other than affiliates) to any one corporation, institution, association, firm, partnership, committee, or person (not an employee of the respondent). Indicate by an asterisk in column (c) each item that includes payments for materials furnished incidental to the service performed. Payments to a recipient by two or more companies within a single system under a cost sharing or other joint arrangement shall be considered a single item for reporting in this schedule and shall be shown in the report of the principal company in the joint arrangement (as measured by gross operating revenues) with references thereto in the reports of the other system companies in the joint arrangement.
2. If more convenient, this schedule may be filled out for a group of companies considered as one system and shown only in the report of the principal company in the system, with references thereto in the reports of the other companies.

	Name of Recipient (a)	Nature of Service (b)	Amount of Payment Allocated to Oregon (c)
1	ADECCO	Management Services	$ 2,067
2	AERITAE CONSULTING GROUP LTD	IT Services	1,848
3	AGREE TECHNOLOGIES AND SOLUTIO	Energy Efficiency Services	10,300
4	ANDERSON BANDUCCI PLLC	Legal Services	1,847
5	BAKER BOTTS LLP	Legal Services	2,571.48
6	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	20,181
7	BAYSWATER LLC	Legal Services	1,249
8	BROWN AND CALDWELL	Legal Services	7,177
9	CASE FORENSICS CORPORATION	Management Services	1,623
10	CGI TECHNOLOGIES AND SOLUTIONS	IT Services	16,426
11	CLEAREDGE PARTNERS INC	Management Services	5,742
12	CLEARESULT CONSULTING INC	Management Services	4,290
13	CME, INC. OF IDAHO	Management Services	2,418
14	COMPUNET, INC	IT Services	3,631
15	COPPERLEAF TECHNOLOGIES INC	Management Services	6,638
16	CORPORATE OFFICE INSTALLATIONS	Management Services	5,399
17	DAVIS WRIGHT TREMAINE LLP	Legal Services	53,729
18	ENERNOC INC	Management Services	24,671
19	EVERGREEN CONSULTING GROUP, LL	Management Services	19,827
20	GIVENS PURSLEY LLP	Legal Services	4,293
21	GOOD TECHNOLOGY CORP.	IT Services	1,382
22	HONEYWELL INTERNATIONAL INC	Management Services	20,624
23	IDL	Management Services	1,205
24	INTELLITECT	Management Services	11,901
25	LEIDOS ENGINEERING LLC	Engineering Services	4,664
26	MAINLINE INFORMATION SYSTEMS I	Management Services	4,019
27	MCDOWELL RACKNER & GIBSON PC	Legal Services	28,523
28	MIRANDE, MICHAEL	Legal Services	1,813
29	NAVIGANT CONSULTING INC	Management Services	5,203
30	NETIQ	IT Services	2,354
31	NEXTATECHN	IT Services	2,536
32	NIELSEN GROUP INC	IT Services	9,183
33	PARSONS BEHLE & LATIMER	Legal Services	1,328
34	PERKINS COIE LLP	Legal Services	13,134
35	POWERPLAN CONSULTANTS INC	Management Services	4,743
36	PRICEWATERHOUSE COOPERS LLP	Management Services	2,603
37	RM ENERGY CONSULTING	Management Services	14,162
38	RUDEEN & ASSOCIATES	Management Services	7,156
39	SCHWABE WILLIAMSON & WYATT	Legal Services	2,960
40	STANLEY ASSOCIATES, INC	IT Services	13,098
41	STOEL RIVES LLP	Legal Services	11,194
42	SULLIVAN & CROMWELL	Legal Services	9,979
43	TATA AMERICA INTERNATIONAL COR	Management Services	63,289
44	TRINOOR LLC	HR Consulting	6,045
45	TUERI LLC	Management Services	3,492
46	UNIVERSITY OF IDAHO	Management Services	18,272
47	XHANCE BUSINESS SOLUTIONS INC	Management Services	1,716
	TOTAL		$ 462,507